Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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July 14, 2006

William A. Bonnet
Vice President
Government & Community Affairs

FILED
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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 05-0069
<u>Energy Efficiency Docket</u>

In accordance with the proposed amended procedural schedule in this proceeding filed June 21, 2006 by the Consumer Advocate, on behalf of all the parties/participants, attached are HECO/HELCO/MECO's responses to information requests on its Final Statement of Position of received from the Consumer Advocate, Department of Defense, Rocky Mountain Institute, Hawaii Solar Energy Association, Hawaii Renewable Energy Alliance, The Gas Company, Life of the Land and Kauai Island Utility Cooperative. HECO/HELCO/MECO did not receive any information requests from the County of Kauai and the County of Maui.

Sincerely,

Attachments

cc: Division of Consumer Advocacy
K. Davoodi
R. Young, Esq.
B. Moto, Esq.
H. Curtis
K. Datta
C. Freedman
R. Reed
W. Bollmeier II
J. Crouch
H. A. Dutch Achenbach
G. T. Aoki, Esq.
L. D. H. Nakazawa, Esq.

CA/HECO-IR-1 **Ref: Final Statement of Position.**

On page 9, the Company states that goals should be established only for energy efficiency and not for load management. Please explain in detail the justification for not establishing goals for load management programs.

HECO Response:

As indicated in its FSOP, page 9, HECO's understanding is that the issue of statewide goals in this proceeding applies to energy efficiency only, as differentiated from load management (including demand response programs). (The first issue on the statewide energy policy issues is "Whether energy efficiency goals should be established and if so, what the goals should be for the state." Energy efficiency programs are programs that focus on reducing both energy and demand, while load management and demand response programs focus on achieving reductions in demand.) Therefore, HECO did not address goals for load management. However, if the Commission did decide that load management programs should be subject to goals, HECO would propose that they be developed in the IRP process in the same manner as was identified in its FSOP, beginning on page 10, for energy efficiency program goals.

CA/HECO-IR-2 **Ref: Final Statement of Position.**

The Company originally proposed utility administration of all programs, but now (page 19) supports a hybrid approach whereby the utility administers some programs and a third party administers other programs. Please describe in detail all of the reasons for the change in the Company's position.

HECO Response:

Please see pages 19 - 38 of HECO's FSOP.

CA/HECO-IR-6 **Ref: Final Statement of Position.**

On page 30, the Company states that load management programs should remain utility administered programs. Please explain in greater detail why a third party could not administer and operate load management programs in response to instructions from the Company.

HECO Response:

According to the Consumer Advocate, "The DSM program administrator is the entity that will have a central role in the administration, coordination and supervision of DSM programs." (See the CA's FSOP, Appendix E, CA's PSOP, page 22.) For load management programs the coordination of load management includes the crucial decision of when the enrolled load should be interrupted in order to maintain system stability. The utility is in the best position to make that decision based on projections of demand, the status of the generating units and other available resources, and the state of its transmission and distribution systems.

The need for the utility to be the load management program administrator does not necessarily mean that it has to market and enroll customers into the load management programs (as differentiated from administering). Load aggregators have been known to acquire load reduction resources on behalf of utilities or Independent System Operators (ISO) in other jurisdictions. However, the decision of when to activate the resource has always been retained by the utility or ISO.

CA/HECO-IR-8 **Ref: Final Statement of Position.**

On page 41, the Company states that penalties for unmet DSM commitments are not necessary. Please explain in detail why it is appropriate for the Company to be rewarded for good performance, but not penalized for bad performance.

HECO Response:

A properly designed incentive (i.e., one that adequately rewards good performance towards well defined objectives) provides sufficient incentive as demonstrated by HECO's DSM program performance under the existing shareholder incentive mechanism. A properly designed utility incentive does not need to penalize bad performance because the Commission already has the ability to do so under its existing regulatory powers. Therefore, a separate and additional penalty for bad performance is not necessary.

In addition, if "bad performance" in any given year is indicated by program costs exceeding program benefits in the existing shared savings mechanism, then there would be no "reward" to the utility. This has typically been the case for the REWH Program, which can be characterized as marginally cost-ineffective. However, not included in the shared savings mechanism as currently derived is any quantification of benefits such as job creation and reducing the use of fossil fuel related to the installation of solar water heating systems.

CA/HECO-IR-9 **Ref: Final Statement of Position**

On page 44, the Company states that an increase in the customer incentive in the REWH and RNC programs was not reflected in exhibits 7 and 8. Please provide updated copies of exhibits 7, 8, and 10 with the change reflected.

HECO Response:

Please see the attached updated Exhibits 7, 8, 10 and 12 which include the increased REWH and RNC incentive. For illustrative purposes, the calculation of DSM program cost-effectiveness includes utility compensation Alternative No. 2 as proposed by HECO on page 79 of its FSOP. Alternative No. 2 is just one of the three utility compensation proposals being offered by HECO in this docket. These documents also reflect the following corrections to Exhibit 10 identified after the FSOP was filed: end effects after 2025, energy savings at consistent levels of generation, and spurious avoided cost data. The corrections reduced the 20-year planning horizon Lifetime Benefits and Net Benefits, which in turn reduced the benefit/cost ratios. These updated exhibits replace the same exhibits in HECO's FSOP.

ROGRAM: Residential Direct Load Control

Component	20-Year Budget																			
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
umulative Savings (Net System Level):																				
Energy (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand (MW)	6.16	11.00	14.50	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65	14.65
nplementation Costs:																				
Total Incentives	$375,773	$686,787	$946,996	$1,086,818	$1,132,920	$1,176,008	$1,219,059	$1,263,436	$1,309,175	$1,356,315	$1,404,895	$1,454,957	$1,506,541	$1,559,691	$1,614,451	$1,670,864	$1,728,979	$1,788,842	$1,850,502	$1,914,009
Direct Labor																				
Base	$131,473	$181,440	$185,956	$190,615	$195,292	$202,713	$210,416	$218,412	$226,712	$235,327	$244,269	$253,551	$263,186	$273,187	$283,569	$294,344	$305,529	$317,139	$329,191	$341,700
Incremental	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Labor	$131,473	$181,440	$185,956	$190,615	$195,292	$202,713	$210,416	$218,412	$226,712	$235,327	$244,269	$253,551	$263,186	$273,187	$283,569	$294,344	$305,529	$317,139	$329,191	$341,700
Outside Services																				
Implementation	$2,696,788	$2,139,750	$1,526,428	$183,680	$170,669	$177,154	$183,886	$190,874	$198,127	$205,656	$213,471	$221,583	$230,003	$238,743	$247,815	$257,232	$267,007	$277,153	$287,685	$298,617
Equipment																				
Communication Expense/Upgrades	$62,250	$99,128	$118,136	$124,955	$129,703	$134,632	$139,748	$145,058	$150,570	$156,292	$162,231	$168,396	$174,795	$181,437	$188,332	$195,488	$202,917	$210,628	$218,632	$226,940
Distributed Equipment	$10,000	$60,000	$100,000	$25,000	$15,000	$15,570	$16,162	$16,776	$17,413	$18,075	$18,762	$19,475	$20,215	$20,983	$21,780	$22,608	$23,467	$24,359	$25,284	$26,245
Tracking	$11,111	$22,222	$23,066	$23,943	$24,853	$25,797	$26,778	$27,795	$28,851	$29,948	$31,086	$32,267	$33,493	$34,766	$36,087	$37,458	$38,882	$40,359	$41,893	$43,485
Evaluation	$78,952	$81,952	$85,066	$88,299	$91,654	$95,137	$98,752	$102,505	$106,400	$110,443	$114,640	$118,996	$123,518	$128,212	$133,084	$138,141	$143,390	$148,839	$154,495	$160,366
Advertising	$325,000	$415,000	$525,000	$156,250	$153,750	$159,593	$165,657	$171,952	$178,486	$185,269	$192,309	$199,617	$207,202	$215,076	$223,249	$231,732	$240,538	$249,678	$259,166	$269,014
Admin/Misc.	$13,559	$14,302	$14,650	$15,154	$15,665	$16,260	$16,878	$17,520	$18,185	$18,876	$19,594	$20,338	$21,111	$21,913	$22,746	$23,610	$24,507	$25,439	$26,405	$27,409
Total Outside Services	$3,197,660	$2,832,354	$2,392,346	$617,281	$601,294	$624,143	$647,861	$672,479	$698,034	$724,559	$752,092	$780,672	$810,337	$841,130	$873,093	$906,270	$940,709	$976,456	$1,013,561	$1,052,076
Return on Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
tal Program Cost	$3,704,906	$3,700,581	$3,525,298	$1,894,714	$1,929,506	$2,002,864	$2,077,336	$2,154,327	$2,233,920	$2,316,200	$2,401,257	$2,489,180	$2,580,065	$2,674,008	$2,771,112	$2,871,479	$2,975,217	$3,082,437	$3,193,254	$3,307,785

ROGRAM: Commercial Industrial Direct Load Control

Component	20-Year Budget																			
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
umulative Savings (Net System Level):																				
Energy (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand (MW)	2.98	11.31	17.51	24.60	26.03	28.31	30.34	32.11	33.80	34.93	35.18	35.35	35.52	35.69	35.77	35.86	35.94	36.02	36.02	36.02
nplementation Costs:																				
Total Incentives	$227,550	$705,998	$908,544	$1,271,348	$1,415,585	$1,565,554	$1,721,436	$1,883,419	$2,051,696	$2,183,255	$2,231,286	$2,280,374	$2,330,543	$2,381,815	$2,434,215	$2,487,767	$2,542,498	$2,598,433	$2,655,599	$2,714,022
Direct Labor																				
Base	$428,249	$438,569	$450,036	$460,985	$119,604	$124,149	$128,867	$133,764	$138,847	$144,123	$149,599	$155,284	$161,185	$167,310	$173,668	$180,267	$187,117	$194,228	$201,608	$209,270
Incremental	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Labor	$428,249	$438,569	$450,036	$460,985	$119,604	$124,149	$128,867	$133,764	$138,847	$144,123	$149,599	$155,284	$161,185	$167,310	$173,668	$180,267	$187,117	$194,228	$201,608	$209,270
Outside Services																				
Equipment																				
Hardware	$200,000	$250,000	$150,000	$125,000	$34,000	$35,292	$36,633	$38,025	$39,470	$40,970	$42,527	$44,143	$45,820	$47,561	$49,369	$51,245	$53,192	$55,213	$57,312	$59,489
Software and associated equipment	$81,000	$21,000	$29,900	$29,900	$6,000	$6,228	$6,465	$6,710	$6,965	$7,230	$7,505	$7,790	$8,086	$8,393	$8,712	$9,043	$9,387	$9,744	$10,114	$10,498
Meters	$26,300	$31,750	$11,980	$11,970	$11,000	$11,418	$11,852	$12,302	$12,770	$13,255	$13,759	$14,282	$14,824	$15,388	$15,972	$16,579	$17,209	$17,863	$18,542	$19,247
Distributed Equipment	$27,960	$29,022	$30,125	$31,270	$6,000	$6,228	$6,465	$6,710	$6,965	$7,230	$7,505	$7,790	$8,086	$8,393	$8,712	$9,043	$9,387	$9,744	$10,114	$10,498
Tracking	$22,222	$23,066	$23,943	$24,853	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Evaluation	$85,402	$88,647	$92,016	$95,512	$8,000	$8,304	$8,620	$8,947	$9,287	$9,640	$10,006	$10,387	$10,781	$11,191	$11,616	$12,058	$12,516	$12,991	$13,485	$13,997
Engineering Studies	$133,300	$166,625	$38,324	$36,658	$11,000	$11,418	$11,852	$12,302	$12,770	$13,255	$13,759	$14,282	$14,824	$15,388	$15,972	$16,579	$17,209	$17,863	$18,542	$19,247
Advertising	$280,000	$350,000	$191,500	$161,000	$25,000	$25,950	$26,936	$27,960	$29,022	$30,125	$31,270	$32,458	$33,691	$34,972	$36,301	$37,680	$39,112	$40,598	$42,141	$43,742
Admin/Misc.	$187,928	$241,216	$267,198	$310,003	$7,000	$7,266	$7,542	$7,829	$8,126	$8,435	$8,756	$9,088	$9,434	$9,792	$10,164	$10,550	$10,951	$11,367	$11,799	$12,248
Total Outside Services	$1,044,112	$1,201,326	$834,984	$826,166	$108,000	$112,104	$116,364	$120,786	$125,376	$130,140	$135,086	$140,218	$145,547	$151,078	$156,818	$162,778	$168,963	$175,384	$182,048	$188,966
Return on Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
tal Program Cost	$1,699,911	$2,345,893	$2,193,564	$2,558,499	$1,643,189	$1,801,807	$1,966,666	$2,137,968	$2,315,918	$2,457,517	$2,515,971	$2,575,877	$2,637,274	$2,700,202	$2,764,701	$2,830,812	$2,898,579	$2,968,045	$3,039,255	$3,112,257

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Number of New Participants

CIEE

Component	Number of First Year Participants		Rationale for Change
	Rate Case	Proposed Docket	
a. HE Cooling	150	125	According to DSMIS database, fewer cooling measures than originally anticipated.
b. CFL Lighting	50	75	New measure is expected to draw a larger number of participants; this perspective is based on positive market response to HECO's current CFL experience in the residential sector.
c. HE Lighting - T8	100	150	Better than expected market response suggests higher levels of participation than originally anticipated.
d. Delamping	NA	25	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
e. HE Lighting - T5	25	25	No change.
f. HE Lighting - LED Exit	75	75	No change.
g. HE Lighting - Induction	38	10	According to DSMIS database (for CICR), very few measures adopted by customers historically.
h. HE HPS HID	NA	10	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
i. HE Metal Halide	NA	10	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
j. Occupancy Sensors	NA	50	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
k. Premium Efficiency Motors	72	50	According to DSMIS databse, fewer installations than originally thought. Value of 50 represents a modest increase relative to historical program trends.
l. Window Tinting	75	25	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.

Number of New Participants

ICR

Component	Number of First Year Participants		Rationale for Change
	Rate Case	Proposed Docket	
a. Customized Measures	60	70	According to DSMIS, when presciptive measures taken out of customized, the historical number of participants is significantly reduced. However, with a planned elimination of the 2-year payback criteria, the number of participants is expected to rise relative to historical levels (adjusted for the exclusion of prescriptive measures).

Number of New Participants

SH

Component	Number of First Year Participants		Rationale for Change
	Rate Case	Proposed Docket	
a. CFL Package	20,000	60,000	Interim program proposes signficant increase in participation levels for this program relative to rate case projections. This reflects HECO's subsequent projections of short-term capacity shortfalls and its plans to ramp up this program signficantly in the short term. During the 2007-2009 timeframe, projected participation levels drop off signficantly as the market becomes saturated. By 2010, HECO projects no further ESH program activities for CFLs and instead will focus on other longer-term measures.
b. HE Room A/C	7,723	4,000	After conducting a review of the market size for Room Acs, it was concluded that the original participation level would mean that HECO is reaching 50% of the equipment turnover market each year, which was deemed too optimistic. Thus, the level was reduced to 25%, which amounts to roughly 4,000 units per year.
c. HE Split System A/C	2,500	625	HECO does not track split system AC saturation, but estimates that roughly 5000 units turnover each year. HECO expects to capture about 12.5% of the turnover market each year for this measure.
d. Energy Star Ceiling Fans	5,000	2,500	The original projection of 5000 households per year was determined to be far too aggressive given the capital cost that customers would need to outlay to qualify for a rebate. As such, the participation levels were cut in half to reflect more realistic targets.
e. Energy Star Appliances	5,000	5,000	No change.

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Number of New Participants

f. Equipment Servicing	2,500	1,250	This would only apply to CAC and split system AC units, which there are about 35000 units in the service territory. The original figure represented 7% of the market. HECO expects far fewer applications of this measure than originally anticipated, due in large part to the up-front cost that would have to borne by the customer in order to qualify for the rebate.

Number of New Participants

LI

Component	Number of First Year		Rationale for Change
	Rate Case	Proposed Docket	
a. CFL Package	4,000	4,000	No change.
b. Water Heat Package	2,000	2,000	No change.
c. Equipment Servicing	692	0	HECO felt that this measure would be difficult for the outside implementation contractors to implement given that they don't possess the necessary expertise to do servicing of cooling equipment. Also, because of the relatively small number of CAC and split system AC units in this market segment, the measure was dropped from the program.

DLC

Component	Number of First Year		Rationale for Change
	Rate Case	Proposed Docket	
a. Water Heating	8,000	8,990	Implementation experience suggests that rate case projections were slightly underrepresented thus the 12% increase in 2006 participation levels.
b. Air Conditioning	900	100	Projected ramp-up of new program element implies that rate case participation levels won't be achieved until year 3 of the program offerring (2008).

IDLC

Component	Number of First Year		Rationale for Change
	Rate Case	Proposed Docket	
a. Direct Load Control	10	10	No change.
b. Voluntary Load Control	NA	15	This program element added to tap markets that typically don't participate in DLC programs.
c. Small Customer DLC	NA	80	This program element added to tap markets that typically don't participate in DLC programs.

Unit Level Impacts

IEE

Component	Unit-Level Savings				Rationale for Change
	Rate Case		Proposed Docket		
	Energy (kWh/Part)	Peak Demand (kW)	Energy (kWh/Part)	Peak Demand (kW)	
a. HE Cooling	44,383	5.03	67,587	9.68	Greater emphasis on larger systems, drawing on historical experience which indicates higher average impacts led to adjustments in proportion of participants across different building types.
b. CFL Lighting	33,305	5.62	32,740	5.61	Roughly the same in both cases.
c. HE Lighting - T8	29,782	4.16	32,735	4.80	Impacts slightly increased based on historical averages suggesting higher impacts.
d. Delamping	NA	NA	91,376	11.11	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
e. HE Lighting - T5	12,385	2.50	54,655	9.01	Impacts increased significantly to reflect HECO field experience which suggests that larger installations are typically made.
f. HE Lighting - LED Exit	3,070	0.35	3,070	0.35	No change.
g. HE Lighting - Induction	30,585	5.15	2,877	0.62	Impacts reduced significantly to reflect HECO field experience which suggests very few installations, and those that are made typically yield smaller impacts based on estimated small share of total floorarea affected.
h. HE HPS HID	NA	NA	5,818	1.19	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
i. HE Metal Halide	NA	NA	23,669	4.76	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
j. Occupancy Sensors	NA	NA	3,210	0.69	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
k. Premium Efficiency Motors	44,726	8.39	6,653	1.16	Impacts reduced significantly based on DSMIS data. KEMA impact evaluation results used as input for unit-level impact. Previous estimates were based on faulty assumptions in BEST model.
l. Window Tinting	10,208	0.66	10,208	0.66	No change.

Unit Level Impacts

CINC

Component	Unit-Level Savings: Rate Case Energy (kWh/Part)	Rate Case Peak Demand (kW)	Proposed Docket Energy (kWh/Part)	Proposed Docket Peak Demand (kW)	Rationale for Change
a. HE Cooling	40,196	4.22	51,643	8.86	Greater emphasis on larger systems, drawing on historical experience which indicates higher average impacts led to adjustments in proportion of participants across different building types.
b. CFL Lighting	24,478	3.79	24,074	3.74	Roughly the same in both cases.
c. HE Lighting - T8	25,203	0.09	27,721	0.10	Roughly the same in both cases, and estimates in line with recent historical averages for the program.
d. HE Lighting - T5	9,703	1.90	47,064	12.84	Impacts increased significantly to reflect HECO field experience which suggests that larger installations are typically made.
e. HE Lighting - Induction	22,347	3.44	4,502	0.88	Impacts reduced significantly to reflect HECO field experience which suggests very few installations, and those that are made typically yield smaller impacts based on estimated small share of total floorarea affected.
f. HE HPS HID	NA	NA	4,545	0.88	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
g. HE Metal Halide	NA	NA	18,486	3.69	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
h. Occupancy Sensors	NA	NA	3,210	0.69	Measure not included in initial analysis; changed made based on additional input from HECO Energy Services personnel.
i. Premium Efficiency Motors	31,533	6.77	6,653	1.16	Impacts reduced significantly based on DSMIS data. KEMA impact evaluation results used as input for unit-level impact. Previous estimates were based on faulty assumptions in BEST model.
j. Window Tinting	8,878	0.54	8,878	0.54	Roughly the same in both cases.
k. Customized Measures	NA	NA	105,777	11.40	Measure not included in initial analysis. Impacts based on DSMIS historical experience, adjusted with exclusion of measures now included in prescriptive portion of CINC program.

CCR

Component	Unit-Level Savings: Rate Case Energy (kWh/Part)	Rate Case Peak Demand (kW)	Proposed Docket Energy (kWh/Part)	Proposed Docket Peak Demand (kW)	Rationale for Change
a. Customized Measures	152,416	28.79	160,223	20.93	Original estimates based on profile of typical large C&I measures. After consultations with HECO program staff, historical program data was deemed a more appropopriate proxy for characterizing per-participant impacts. Impacts based on DSMIS historical experience, adjusted with exclusion of measures now included in the CIEE program.

Unit Level Impacts

:SH

Component	Unit-Level Savings				Rationale for Change
	Rate Case		Proposed Docket		
	Energy (kWh/Part)	Peak Demand (kW)	Energy (kWh/Part)	Peak Demand (kW)	
a. CFL Package	196	0.04	196	0.04	No change.
b. HE Room A/C	259	0.13	373	0.19	Adjustments to reflect different baseline and high efficiency EERs than originally estimated.
c. HE Split System A/C	487	0.32	545	0.31	Slight adjustments to account for mix of CAC and split system AC whereas before the assumption was strictly CAC.
d. Energy Star Ceiling Fans	395	0.01	395	0.01	No change.
e. Energy Star Appliances	945	0.19	313	0.12	Impacts reduced to reflect assumption that only 1 appliance would be rebated per household, whereas in the prior analysis it was assumed that a customer would adopt all three measure types (Energy Star clothes washer, dishwasher and refrigerator).
f. Equipment Servicing	487	0.32	620	0.39	Slight adjustments to account for mix of CAC and split system AC whereas before the assumption was strictly CAC.

IEWH

Component	Unit-Level Savings				Rationale for Change
	Rate Case		Proposed Docket		
	Energy (kWh/Part)	Peak Demand (kW)	Energy (kWh/Part)	Peak Demand (kW)	
a. Solar Water Heating	3,250	0.73	2,230	0.51	Original values based on generic modeling approach; revised values reflect recent KEMA evaluation estimates.
b. HE Electric Water Heat	200	0.02	160	0.03	Original values based on generic modeling approach; revised values reflect recent KEMA evaluation estimates.

Unit Level Impacts

LI

Component	Unit-Level Savings				Rationale for Change
	Rate Case		Proposed Docket		
	Energy (kWh/Part)	Peak Demand (kW)	Energy (kWh/Part)	Peak Demand (kW)	
a. CFL Package	65.00	0.01	196	0.04	Package made identical to ESH package for consistency (3 bulbs vs. 2 bulbs in previous analysis).
b. Water Heat Package	787.00	0.16	777	0.19	Measure package changed based on HECO field experience suggesting that water heater wraps not effective measure. Revisions resulted in lower energy savings but higher demand impact (due to BEST model anomolies).
c. Equipment Servicing	487.00	0.32	NA	NA	HECO felt that this measure would be difficult for the outside implementation contractors to implement given that they don't possess the necessary expertise to do servicing of cooling equipment. Also, because of the relatively small number of CAC and split system AC units in this market segment, the measure was dropped from the program.

DLC

Component	Unit-Level Savings				Rationale for Change
	Rate Case		Proposed Docket		
	Energy (kWh/Part)	Peak Demand (kW)	Energy (kWh/Part)	Peak Demand (kW)	
a. Water Heating	0.00	0.68	0	0.60	Rate case impact was represented at the gross system level rather than the gross customer level.
b. Air Conditioning	0.00	0.79	0	0.79	No change.

IDLC

Component	Unit-Level Savings				Rationale for Change
	Rate Case		Proposed Docket		
	Energy (kWh/Part)	Peak Demand (kW)	Energy (kWh/Part)	Peak Demand (kW)	
a. Direct Load Control	0.00	350.00	0	75-350	Rate case impact was represented at the gross system level rather than the gross customer level. Range of savings depends on whether customer agrees to have an under-frequency relay (UFR) installed.
b. Voluntary Load Control	NA	NA	0	75-350	Feature not included in rate case. Range of savings depends on whether customer agrees to have a UFR installed.
b. Small Customer DLC	NA	NA	0	5.00	Feature not included in rate case.

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Prepared by Greg Wikler
Global Energy Partners, LLC

Incentives and Implementation

EE

Component	First Year Amount		Rationale for Change
	Rate Case (2005TY)	Proposed Docket (2006)	
)TAL INCENTIVE COSTS	$2,188,753	$2,265,425	Overall, larger number of participants projected relative to rate case projections. Measure level incentives unchanged from rate case.
PLEMENTATION COSTS:			
Direct Labor			
Base	$108,246	$104,220	Differences due to HECO internal methods for estimating labor costs, and are a function of total program costs and general corporate overhead rates.
Incremental	$367,501	$276,642	
Total Labor	$475,747	$380,862	
Outside Services			
Implementation	$229,767	$160,053	Projected lower costs based on more recent field experience.
Tracking	$3,500	$17,778	Higher costs than originally anticipated due to added measures to the program.
Evaluation	$35,632	$81,178	Costs estimated from historical M&E experience; prior value based on industry standard.
Preliminary Energy Assessments	$200,000	$187,500	Projected lower costs based on more recent field experience.
Advertising	$259,035	$170,589	Projected lower costs based on more recent field experience.
Admin/Misc	$239,667	$109,077	Projected lower costs based on more recent field experience.
Total Outside Services	$967,601	$726,175	
TOTAL IMPLEMENTATION:	$1,443,348	$1,107,037	

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Incentives and Implementation

INC

Component	First Year Amount		Rationale for Change
	Rate Case (2005TY)	Proposed Docket (2006)	
OTAL INCENTIVE COSTS	$812,837	$936,019	Overall, larger number of participants projected relative to rate case projections. Measure level incentives unchanged from rate case. Also, addition of Customized measures results in higher overall costs.
IPLEMENTATION COSTS:			
Direct Labor			
Base	$48,165	$114,573	Differences due to HECO internal methods for estimating labor costs, and are a function of total program costs and general corporate overhead rates.
Incremental	$166,087	$222,725	
Total Labor	$214,252	$337,298	
Outside Services			
Implementation	$171,910	$72,501	Projected lower costs based on more recent field experience.
Tracking	$3,500	$17,778	Higher costs than originally anticipated due to added measures to the program.
Evaluation	$14,495	$38,864	Costs estimated from historical M&E experience; prior value based on industry standard.
Design Assistance	$100,000	$100,000	No change.
Advertising	$79,182	$81,599	Projected slightly higher costs based on more recent field experience.
Admin/Misc	$72,154	$53,890	Projected lower costs based on more recent field experience.
Total Outside Services	$441,241	$364,632	
TOTAL IMPLEMENTATION:	$655,493	$701,930	

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Incentives and Implementation

ICR

Component	First Year Amount		Rationale for Change
	Rate Case (2005TY)	Proposed Docket (2006)	
OTAL INCENTIVE COSTS	$1,824,715	$743,936	Overall, smaller number of participants projected relative to rate case due to the shift of several measures over to CIEE. Incentive levels unchanged from rate case.
IPLEMENTATION COSTS:			
Direct Labor			
Base	$61,661	$145,807	Differences due to HECO internal methods for estimating labor costs, and are a function of total program costs and general corporate overhead rates.
Incremental	$299,864	$371,503	
Total Labor	$361,525	$517,310	
Outside Services			
Implementation	$309,482	$36,225	Projected lower costs based on more recent field experience.
Tracking	$3,500	$17,778	Higher costs than originally anticipated due to added measures (i.e., those with < 2 year payback) to the program.
Evaluation	$29,147	$44,890	Costs estimated from historical M&E experience; prior value based on industry standard.
Feasibility Studies	$125,000	$175,000	Projected higher costs due to more emphasis on pure customized measures plus further assessment required due to addition of < 2-year payback measures.
Advertising	$145,770	$107,061	Projected lower costs due to fewer participants in the program and good customer awareness of the program.
Admin/Misc	$146,841	$66,176	Projected lower costs based on more recent field experience.
Total Outside Services	$759,740	$447,130	
TOTAL IMPLEMENTATION:	$1,121,265	$964,440	

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Incentives and Implementation

SH

Component	First Year Amount		Rationale for Change
	Rate Case (2005TY)	Proposed Docket (2006)	
OTAL INCENTIVE COSTS	$2,137,857	$1,231,250	Projected lower due to smaller projected number of participants. Incentive levels unchanged from rate case.
IPLEMENTATION COSTS:			
Direct Labor			
Base	$0	$51,691	Differences due to HECO internal methods for estimating labor costs, and are a function of total program costs and general corporate overhead rates.
Incremental	$0	$15,393	
Total Labor	$0	$67,084	
Outside Services			
Implementation	$200,000	$120,000	Lower implementation costs due to shift from implementation contractor to direct labor for program implementation.
Tracking	$12,000	$11,111	Costs made equivalent across all residential programs.
Evaluation	$27,287	$15,000	Projected lower costs based on revised assumption; prior value based on industry standard.
Advertising	$330,000	$500,000	Advertising budget increased in 2006 due to need for building public awareness of CFLs and other new measures being offered under the program. Budgets reduced in future years.
Admin/Misc	$48,892	$25,000	Projected lower costs based on revised assumption.
Total Outside Services	$618,179	$671,111	
TOTAL IMPLEMENTATION:	$618,179	$738,195	

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Incentives and Implementation

DLC

Component	First Year Amount		Rationale for Change
	Rate Case (2005TY)	Proposed Docket (2006)	
)TAL INCENTIVE COSTS	$573,125	$227,550	Incentive amount discounted for new 2006 particpants to recognize that not all participants come onto the program at the beginning of the year thus there is a reduction in the total year incentive.
PLEMENTATION COSTS:			
Direct Labor			
Base	$12,746	$428,249	Differences due to HECO internal methods for estimating labor costs, and
Incremental	$106,697	$0	are a function of total program costs and general corporate overhead rates.
Total Labor	$119,443	$428,249	Direct labor costs added to provide management of outside contractors
Outside Services			
Implementation	$56,250	$0	Costs represented in HECO labor.
Equipment	$25,950	$335,260	Equipment costs were not expensed in the rate case.
Tracking	$0	$22,222	
Evaluation	$0	$85,902	
Engineering Studies	NA	$133,300	
Advertising	$6,228	$280,000	
Admin/Misc	$0	$187,928	
Total Outside Services	$88,428	$1,044,612	
TOTAL IMPLEMENTATION:	$207,871	$1,472,861	

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TABLE 1. CIEE: DETAILED SUMMARY FOR 2006 START YEAR – 20-YEAR PLANNING HORIZON SUMMARY
PROGRAM NAME: COMMERCIAL INDUSTRIAL ENERGY EFFICIENCY

Discount Rate	8%
General Escalation Rate	2.2%
Measure Lifetime (years)	15

	Benefits	Costs	Net Benefits	B/C Ratio
Participant Test	$269,643,410	$73,172,479	$196,470,931	3.69
Ratepayer Impact Measure Test	$148,324,126	$308,494,215	($160,170,089)	0.48
Utility Cost Test	$148,324,126	$38,850,805	$109,473,321	3.82
Total Resource Cost Test	$148,324,126	$88,144,874	$60,179,252	1.68

	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Cumulative Savings (Net System Level)											
Peak Demand Reduction (kW)		2,284	4,567	6,851	9,135	11,418	13,697	15,661	17,590	19,493	21,396
Energy Savings (kWh)		15,266,176	30,532,351	45,798,527	61,064,703	76,330,878	91,575,903	105,015,883	118,281,870	131,429,865	144,577,860
Rates											
Demand ($/kW)		$46.00	$47.01	$48.05	$49.10	$50.18	$51.29	$52.42	$53.57	$54.75	$55.95
Energy ($/kWh)		$0.1130	$0.1154	$0.1180	$0.1206	$0.1232	$0.1259	$0.1287	$0.1315	$0.1344	$0.1374
BENEFIT CALCULATIONS:											
Avoided Costs (Utility, Ratepayer)	NPV										
Demand		$441,048	$885,048	$1,330,048	$1,773,895	$0	$0	$0	$0	$0	$35,064,632
Energy		$1,792,218	$3,504,260	$5,012,523	$6,990,435	$8,085,333	$9,847,639	$11,701,552	$13,134,828	$15,323,092	-$21,625,198
Total	$148,324,126	$2,233,266	$4,389,308	$6,342,571	$8,764,330	$8,085,333	$9,847,639	$11,701,552	$13,134,828	$15,323,092	$13,439,434
Avoided Costs (Total Resource)											
Demand		$441,048	$885,048	$1,330,048	$1,773,895	$0	$0	$0	$0	$0	$35,064,632
Energy		$1,792,218	$3,504,260	$5,012,523	$6,990,435	$8,085,333	$9,847,639	$11,701,552	$13,134,828	$15,323,092	-$21,625,198
Total	$148,324,126	$2,233,266	$4,389,308	$6,342,571	$8,764,330	$8,085,333	$9,847,639	$11,701,552	$13,134,828	$15,323,092	$13,439,434
Avoided Costs (Participant)											
Demand		$142,900	$292,087	$447,769	$610,160	$779,479	$955,632	$1,116,715	$1,281,832	$1,451,750	$1,628,523
Energy		$2,306,872	$4,715,246	$7,228,472	$9,849,998	$12,583,372	$15,428,684	$18,082,295	$20,814,580	$23,637,113	$26,573,763
Total	$269,643,410	$2,449,771	$5,007,332	$7,676,241	$10,460,157	$13,362,851	$16,384,316	$19,199,010	$22,096,412	$25,088,862	$28,202,286
COST CALCULATIONS:											
Cost Inputs:											
Implementation		$1,107,037	$1,133,931	$1,171,498	$1,197,612	$1,234,588	$1,281,502	$1,330,199	$1,380,747	$1,433,215	$1,487,677
Incentives		$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425
Participant		$5,917,290	$6,047,470	$6,180,515	$6,316,486	$6,455,449	$6,597,469	$6,742,613	$6,890,950	$7,042,551	$7,197,487
	NPV										
Total Participant Costs	$73,172,479	$5,917,290	$6,047,470	$6,180,515	$6,316,486	$6,455,449	$6,597,469	$6,742,613	$6,890,950	$7,042,551	$7,197,487
Total RIM Costs	$308,494,215	$5,822,233	$8,406,688	$11,113,163	$13,923,194	$16,862,864	$19,931,243	$22,794,635	$25,742,584	$28,787,503	$31,955,388
Total Utility Costs	$38,850,805	$3,372,462	$3,399,356	$3,436,922	$3,463,037	$3,500,013	$3,546,927	$3,595,624	$3,646,172	$3,698,640	$3,753,102
Total TRC Costs	$88,144,874	$7,024,327	$7,181,401	$7,352,012	$7,514,098	$7,690,036	$7,878,971	$8,072,812	$8,271,697	$8,475,766	$8,685,165

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cumulative Savings (Net System Level)										
Peak Demand Reduction (kW)	22,384	23,373	24,361	25,349	26,337	27,273	27,305	27,337	27,369	27,401
Energy Savings (kWh)	151,432,516	158,287,172	165,141,829	171,996,485	178,851,141	185,418,506	185,775,374	186,132,243	186,489,111	186,845,980
Rates										
Demand ($/kW)	$57.18	$58.44	$59.73	$61.04	$62.38	$63.76	$65.16	$66.59	$68.06	$69.55
Energy ($/kWh)	$0.1404	$0.1435	$0.1467	$0.1499	$0.1532	$0.1566	$0.1600	$0.1635	$0.1671	$0.1708
BENEFIT CALCULATIONS:										
Avoided Costs (Utility, Ratepayer)										
Demand	$40,840,558	$38,489,308	$36,863,292	$35,414,272	$34,050,236	$33,585,019	$32,530,838	$31,522,493	-$12,059,583	-$21,835,600
Energy	-$21,516,311	-$20,165,434	-$20,402,348	-$20,080,695	-$20,028,711	-$19,862,257	-$21,747,369	-$22,209,141	$27,521,466	$28,909,613
Total	$19,324,246	$18,323,874	$16,460,944	$15,333,578	$14,021,525	$13,722,762	$10,783,469	$9,313,352	$15,461,883	$7,074,013
Avoided Costs (Total Resource)										
Demand	$40,840,558	$38,489,308	$36,863,292	$35,414,272	$34,050,236	$33,585,019	$32,530,838	$31,522,493	-$12,059,583	-$21,835,600
Energy	-$21,516,311	-$20,165,434	-$20,402,348	-$20,080,695	-$20,028,711	-$19,862,257	-$21,747,369	-$22,209,141	$27,521,466	$28,909,613
Total	$19,324,246	$18,323,874	$16,460,944	$15,333,578	$14,021,525	$13,722,762	$10,783,469	$9,313,352	$15,461,883	$7,074,013
Avoided Costs (Participant)										
Demand	$1,741,229	$1,858,105	$1,979,281	$2,104,890	$2,235,067	$2,365,420	$2,420,292	$2,476,433	$2,533,873	$2,592,642
Energy	$28,446,006	$30,387,766	$32,401,196	$34,488,509	$36,651,981	$38,833,784	$39,764,514	$40,717,400	$41,692,967	$42,691,752
Total	$30,187,235	$32,245,871	$34,380,477	$36,593,398	$38,887,048	$41,199,204	$42,184,805	$43,193,833	$44,226,840	$45,284,393
COST CALCULATIONS:										
Cost Inputs:										
Implementation	$1,544,209	$1,602,889	$1,663,799	$1,727,023	$1,792,650	$1,860,771	$1,931,480	$2,004,876	$2,081,062	$2,160,142
Incentives	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425	$2,265,425
Participant	$7,355,832	$7,517,660	$7,683,049	$7,852,076	$8,024,822	$8,201,368	$8,381,798	$8,566,197	$8,754,654	$8,947,256
Total Participant Costs	$7,355,832	$7,517,660	$7,683,049	$7,852,076	$8,024,822	$8,201,368	$8,381,798	$8,566,197	$8,754,654	$8,947,256
Total RIM Costs	$33,996,869	$36,114,185	$38,309,701	$40,585,847	$42,945,123	$45,325,400	$46,381,710	$47,464,134	$48,573,326	$49,709,960
Total Utility Costs	$3,809,634	$3,868,314	$3,929,224	$3,992,448	$4,058,075	$4,126,196	$4,196,905	$4,270,301	$4,346,487	$4,425,567
Total TRC Costs	$8,900,041	$9,120,549	$9,346,848	$9,579,099	$9,817,472	$10,062,139	$10,313,278	$10,571,074	$10,835,715	$11,107,398

TABLE 3. CICR: DETAILED SUMMARY FOR 2006 START YEAR -- 20-YEAR PLANNING HORIZON SUMMARY
PROGRAM NAME: COMMERCIAL INDUSTRIAL CUSTOM REBATES

Discount Rate	8%
General Escalation Rate	2.2%
Measure Lifetime (years)	15

	Benefits	Costs	Net Benefits	B/C Ratio
Participant Test	$169,435,107	$82,556,660	$86,878,447	2.05
Ratepayer Impact Measure Test	$93,057,860	$190,299,444	($97,241,584)	0.49
Utility Cost Test	$93,057,860	$20,864,337	$72,193,523	4.46
Total Resource Cost Test	$93,057,860	$95,579,644	($2,521,784)	0.97

	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Cumulative Savings (Net System Level)											
Peak Demand Reduction (kW)		1,245	2,491	3,736	4,981	6,227	7,472	8,718	9,963	11,208	12,454
Energy Savings (kWh)		9,583,078	19,166,156	28,749,233	38,332,311	47,915,389	57,498,467	67,081,544	76,664,622	86,247,700	95,830,778
Rates											
Demand ($/kW)		$46.00	$47.01	$48.05	$49.10	$50.18	$51.29	$52.42	$53.57	$54.75	$55.95
Energy ($/kWh)		$0.1130	$0.1154	$0.1180	$0.1206	$0.1232	$0.1259	$0.1287	$0.1315	$0.1344	$0.1374
BENEFIT CALCULATIONS:		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Avoided Costs (Utility, Ratepayer)	NPV										
Demand		$240,522	$482,654	$725,332	$967,381	$0	$0	$0	$0	$0	$20,409,563
Energy		$1,125,034	$2,199,739	$3,146,525	$4,388,125	$5,075,428	$6,183,113	$7,474,662	$8,513,364	$10,055,412	-$14,333,865
Total	$93,057,860	$1,365,556	$2,682,393	$3,871,857	$5,355,506	$5,075,428	$6,183,113	$7,474,662	$8,513,364	$10,055,412	$6,075,698
Avoided Costs (Total Resource)											
Demand		$240,522	$482,654	$725,332	$967,381	$0	$0	$0	$0	$0	$20,409,563
Energy		$1,125,034	$2,199,739	$3,146,525	$4,388,125	$5,075,428	$6,183,113	$7,474,662	$8,513,364	$10,055,412	-$14,333,865
Total	$93,057,860	$1,365,556	$2,682,393	$3,871,857	$5,355,506	$5,075,428	$6,183,113	$7,474,662	$8,513,364	$10,055,412	$6,075,698
Avoided Costs (Participant)											
Demand		$67,046	$137,042	$210,085	$286,276	$365,717	$448,516	$534,780	$624,623	$718,160	$815,511
Energy		$1,273,560	$2,603,156	$3,990,638	$5,437,910	$6,946,930	$8,519,715	$10,158,340	$11,864,941	$13,641,716	$15,490,927
Total	$169,435,107	$1,340,606	$2,740,198	$4,200,723	$5,724,186	$7,312,647	$8,968,231	$10,693,120	$12,489,564	$14,359,877	$16,306,438
COST CALCULATIONS:											
Cost Inputs:											
Implementation		$964,440	$994,357	$1,020,355	$1,047,560	$1,072,158	$1,112,900	$1,155,190	$1,199,087	$1,244,652	$1,291,949
Incentives		$743,936	$743,936	$743,936	$743,936	$743,936	$743,936	$743,936	$743,936	$743,936	$743,936
Participant		$5,529,133	$6,819,165	$6,982,447	$7,149,912	$7,321,677	$7,497,865	$7,678,601	$7,864,015	$8,054,241	$8,249,418
	NPV										
Total Participant Costs	$82,556,660	$5,529,133	$6,819,165	$6,982,447	$7,149,912	$7,321,677	$7,497,865	$7,678,601	$7,864,015	$8,054,241	$8,249,418
Total RIM Costs	$190,299,444	$3,048,981	$4,478,490	$5,965,014	$7,515,681	$9,128,740	$10,825,066	$12,592,246	$14,432,587	$16,348,465	$18,342,323
Total Utility Costs	$20,864,337	$1,708,376	$1,738,292	$1,764,290	$1,791,495	$1,816,093	$1,856,835	$1,899,125	$1,943,023	$1,988,588	$2,035,885
Total TRC Costs	$95,579,644	$6,493,573	$7,813,521	$8,002,802	$8,197,472	$8,393,835	$8,610,765	$8,833,791	$9,063,102	$9,298,894	$9,541,368

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cumulative Savings (Net System Level)										
Peak Demand Reduction (kW)	13,699	14,944	16,190	17,435	18,680	18,680	18,680	18,680	18,680	18,680
Energy Savings (kWh)	105,413,856	114,996,933	124,580,011	134,163,089	143,746,167	143,746,167	143,746,167	143,746,167	143,746,167	143,746,167
Rates										
Demand ($/kW)	$57.18	$58.44	$59.73	$61.04	$62.38	$63.76	$65.16	$66.59	$68.06	$69.55
Energy ($/kWh)	$0.1404	$0.1435	$0.1467	$0.1499	$0.1532	$0.1566	$0.1600	$0.1635	$0.1671	$0.1708
BENEFIT CALCULATIONS:	2016	2017	2018	2019	2020	2021	2022	2023	2024	2
Avoided Costs (Utility, Ratepayer)										
Demand	$24,994,117	$24,609,980	$24,498,588	$24,357,852	$24,150,921	$23,003,420	$22,255,303	$21,540,256	-$8,231,050	-$14,886,113
Energy	-$14,977,743	-$14,650,354	-$15,391,163	-$15,663,623	-$16,097,468	-$15,398,265	-$16,827,316	-$17,151,670	$21,213,599	$22,241,025
Total	$10,016,374	$9,959,626	$9,107,425	$8,694,229	$8,053,453	$7,605,154	$5,427,987	$4,388,585	$12,982,550	$7,354,912
Avoided Costs (Total Resource)										
Demand	$24,994,117	$24,609,980	$24,498,588	$24,357,852	$24,150,921	$23,003,420	$22,255,303	$21,540,256	-$8,231,050	-$14,886,113
Energy	-$14,977,743	-$14,650,354	-$15,391,163	-$15,663,623	-$16,097,468	-$15,398,265	-$16,827,316	-$17,151,670	$21,213,599	$22,241,025
Total	$10,016,374	$9,959,626	$9,107,425	$8,694,229	$8,053,453	$7,605,154	$5,427,987	$4,388,585	$12,982,550	$7,354,912
Avoided Costs (Participant)										
Demand	$916,797	$1,022,146	$1,131,686	$1,245,551	$1,363,878	$1,393,883	$1,424,549	$1,455,889	$1,487,919	$1,520,653
Energy	$17,414,900	$19,416,030	$21,496,781	$23,659,688	$25,907,359	$26,477,321	$27,059,822	$27,655,138	$28,263,551	$28,885,349
Total	$18,331,697	$20,438,176	$22,628,467	$24,905,239	$27,271,237	$27,871,204	$28,484,371	$29,111,027	$29,751,469	$30,406,002
COST CALCULATIONS:										
Cost Inputs:										
Implementation	$1,341,043	$1,392,003	$1,444,899	$1,499,805	$1,556,798	$1,615,956	$1,677,363	$1,741,102	$1,807,264	$1,875,940
Incentives	$743,936	$743,936	$743,936	$743,936	$743,936	$743,936	$743,936	$743,936	$743,936	$743,936
Participant	$8,449,690	$8,655,202	$8,866,109	$9,082,568	$9,304,740	$9,532,795	$9,766,905	$10,007,251	$10,254,018	$10,507,397
Total Participant Costs	$8,449,690	$8,655,202	$8,866,109	$9,082,568	$9,304,740	$9,532,795	$9,766,905	$10,007,251	$10,254,018	$10,507,397
Total RIM Costs	$20,416,676	$22,574,115	$24,817,302	$27,148,980	$29,571,970	$30,231,096	$30,905,669	$31,596,065	$32,302,669	$33,025,877
Total Utility Costs	$2,084,979	$2,135,938	$2,188,835	$2,243,741	$2,300,733	$2,359,892	$2,421,298	$2,485,038	$2,551,200	$2,619,876
Total TRC Costs	$9,790,733	$10,047,205	$10,311,008	$10,582,373	$10,861,538	$11,148,751	$11,444,268	$11,748,354	$12,061,282	$12,383,3

TABLE 6. RNC: DETAILED SUMMARY FOR 2006 START YEAR -- 20-YEAR PLANNING HORIZON SUMMARY
PROGRAM NAME: RESIDENTIAL NEW CONSTRUCTION PROGRAM

Discount Rate	8%
General Escalation Rate	2.2%
Measure Lifetime (years)	15

	Benefits	Costs	Net Benefits	B/C Ratio
Participant Test	$27,733,442	$23,403,595	$4,329,847	1.19
Ratepayer Impact Measure Test	$46,123,329	$50,493,786	($4,370,457)	0.91
Utility Cost Test	$46,123,329	$22,760,344	$23,362,985	2.03
Total Resource Cost Test	$46,123,329	$33,044,263	$13,079,066	1.40

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Cumulative Savings (Net System Level)											
Peak Demand Reduction (kW)		787	1,263	1,894	2,525	3,157	3,788	4,419	5,051	5,682	6,274
Energy Savings (kWh)		2,542,113	5,491,915	8,237,872	10,983,830	13,729,787	16,475,745	19,221,702	21,967,660	24,713,617	27,275,745
Rates											
Demand ($/kW)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy ($/kWh)		$0.0810	$0.0828	$0.0846	$0.0865	$0.0884	$0.0904	$0.0923	$0.0944	$0.0964	$0.0986
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BENEFIT CALCULATIONS:											
Avoided Costs (Utility, Ratepayer)	NPV										
Demand		$151,950	$244,685	$367,711	$490,420	$0	$0	$0	$0	$0	$10,282,555
Energy		$298,439	$630,318	$901,613	$1,257,384	$1,454,325	$1,771,724	$2,141,807	$2,439,439	$2,881,301	-$4,079,763
Total	$46,123,329	$450,389	$875,003	$1,269,324	$1,747,803	$1,454,325	$1,771,724	$2,141,807	$2,439,439	$2,881,301	$6,202,792
Avoided Costs (Total Resource)											
Demand		$151,950	$244,685	$367,711	$490,420	$0	$0	$0	$0	$0	$10,282,555
Energy		$298,439	$630,318	$901,613	$1,257,384	$1,454,325	$1,771,724	$2,141,807	$2,439,439	$2,881,301	-$4,079,763
Total	$46,123,329	$450,389	$875,003	$1,269,324	$1,747,803	$1,454,325	$1,771,724	$2,141,807	$2,439,439	$2,881,301	$6,202,792
Avoided Costs (Participant)											
Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy		$206,775	$456,538	$699,873	$953,693	$1,218,343	$1,494,176	$1,781,556	$2,080,857	$2,392,465	$2,698,590
Total	$27,733,442	$206,775	$456,538	$699,873	$953,693	$1,218,343	$1,494,176	$1,781,556	$2,080,857	$2,392,465	$2,698,590
COST CALCULATIONS:											
Cost Inputs:											
Implementation		$720,207	$717,593	$743,080	$769,299	$796,684	$826,958	$858,382	$891,001	$924,859	$960,003
Incentives		$1,252,000	$1,459,893	$1,039,893	$1,069,893	$1,099,893	$1,129,893	$1,159,893	$1,189,893	$1,219,893	$1,249,893
Participant		$2,211,830	$2,756,570	$1,868,530	$1,909,638	$1,951,650	$1,994,587	$2,038,467	$2,083,314	$2,129,147	$2,175,988
	NPV										
Total Participant Costs	$23,403,595	$2,211,830	$2,756,570	$1,868,530	$1,909,638	$1,951,650	$1,994,587	$2,038,467	$2,083,314	$2,129,147	$2,175,988
Total RIM Costs	$50,493,786	$2,178,982	$2,634,023	$2,482,845	$2,792,885	$3,114,919	$3,451,026	$3,799,831	$4,161,750	$4,537,217	$4,908,486
Total Utility Costs	$22,760,344	$1,972,207	$2,177,486	$1,782,972	$1,839,192	$1,896,576	$1,956,850	$2,018,275	$2,080,893	$2,144,751	$2,209,896
Total TRC Costs	$33,044,263	$2,932,037	$3,474,163	$2,611,610	$2,678,937	$2,748,334	$2,821,544	$2,896,850	$2,974,314	$3,054,005	$3,135,991

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cumulative Savings (Net System Level)										
Peak Demand Reduction (kW)	6,866	7,459	8,051	8,643	9,235	9,235	9,235	9,235	9,235	9,235
Energy Savings (kWh)	29,837,872	32,400,000	34,962,128	37,524,255	40,086,383	40,086,383	40,086,383	40,086,383	40,086,383	40,086,383
Rates										
Demand ($/kW)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy ($/kWh)	$0.1007	$0.1030	$0.1052	$0.1075	$0.1099	$0.1123	$0.1148	$0.1173	$0.1199	$0.122[illegible]
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2
BENEFIT CALCULATIONS:										
Avoided Costs (Utility, Ratepayer)										
Demand	$12,527,981	$12,282,659	$12,182,609	$12,074,738	$11,939,602	$11,372,306	$11,002,456	$10,648,955	-$4,069,222	-$7,359,316
Energy	-$4,239,518	-$4,127,688	-$4,319,375	-$4,380,980	-$4,489,088	-$4,294,102	-$4,692,621	-$4,783,073	$5,915,820	$6,202,338
Total	$8,288,462	$8,154,971	$7,863,234	$7,693,758	$7,450,513	$7,078,204	$6,309,836	$5,865,882	$1,846,598	-$1,156,978
Avoided Costs (Total Resource)										
Demand	$12,527,981	$12,282,659	$12,182,609	$12,074,738	$11,939,602	$11,372,306	$11,002,456	$10,648,955	-$4,069,222	-$7,359,316
Energy	-$4,239,518	-$4,127,688	-$4,319,375	-$4,380,980	-$4,489,088	-$4,294,102	-$4,692,621	-$4,783,073	$5,915,820	$6,202,338
Total	$8,288,462	$8,154,971	$7,863,234	$7,693,758	$7,450,513	$7,078,204	$6,309,836	$5,865,882	$1,846,598	-$1,156,978
Avoided Costs (Participant)										
Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy	$3,017,026	$3,348,166	$3,692,417	$4,050,195	$4,421,927	$4,519,210	$4,618,632	$4,720,242	$4,824,087	$4,930,217
Total	$3,017,026	$3,348,166	$3,692,417	$4,050,195	$4,421,927	$4,519,210	$4,618,632	$4,720,242	$4,824,087	$4,930,217
COST CALCULATIONS:										
Cost Inputs:										
Implementation	$996,483	$1,034,350	$1,073,655	$1,114,454	$1,156,803	$1,200,762	$1,246,391	$1,293,754	$1,342,916	$1,393,947
Incentives	$1,279,893	$1,309,893	$1,339,893	$1,369,893	$1,399,893	$1,399,893	$1,399,893	$1,399,893	$1,399,893	$1,399,893
Participant	$2,223,860	$2,272,784	$2,322,786	$2,373,887	$2,426,113	$2,479,487	$2,534,036	$2,589,785	$2,646,760	$2,704,988
Total Participant Costs	$2,223,860	$2,272,784	$2,322,786	$2,373,887	$2,426,113	$2,479,487	$2,534,036	$2,589,785	$2,646,760	$2,704,988
Total RIM Costs	$5,293,402	$5,692,409	$6,105,965	$6,534,541	$6,978,623	$7,119,864	$7,264,916	$7,413,888	$7,566,896	$7,724,057
Total Utility Costs	$2,276,376	$2,344,243	$2,413,548	$2,484,347	$2,556,696	$2,600,654	$2,646,283	$2,693,646	$2,742,809	$2,793,840
Total TRC Costs	$3,220,343	$3,307,134	$3,396,441	$3,488,341	$3,582,916	$3,680,249	$3,780,426	$3,883,538	$3,989,676	$4,098,5

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TABLE 7. RLI: DETAILED SUMMARY FOR 2006 START YEAR -- 20-YEAR PLANNING HORIZON SUMMARY
PROGRAM NAME: RESIDENTIAL LOW INCOME

Discount Rate	8%
General Escalation Rate	2.2%
Measure Lifetime (years)	15

	Benefits	Costs	Net Benefits	B/C Ratio
Participant Test	$19,775,962	$7,283,502	$12,492,461	2.72
Ratepayer Impact Measure Test	$37,611,515	$30,696,412	$6,915,104	1.23
Utility Cost Test	$37,611,515	$10,920,449	$26,691,066	3.44
Total Resource Cost Test	$37,611,515	$11,995,675	$25,615,841	3.14

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Cumulative Savings (Net System Level)											
Peak Demand Reduction (kW)		591	1,182	1,773	2,364	2,954	3,381	3,807	4,233	4,659	5,085
Energy Savings (kWh)		2,633,290	5,266,579	7,899,869	10,533,159	13,166,449	14,916,759	16,667,069	18,417,379	20,167,689	21,917,999
Rates											
Demand ($/kW)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy ($/kWh)		$0.0810	$0.0828	$0.0846	$0.0865	$0.0884	$0.0904	$0.0923	$0.0944	$0.0964	$0.0986
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
BENEFIT CALCULATIONS:											
Avoided Costs (Utility, Ratepayer)	NPV										
Demand		$114,120	$229,003	$344,145	$458,989	$0	$0	$0	$0	$0	$8,333,376
Energy		$309,143	$604,456	$864,619	$1,205,793	$1,394,654	$1,604,078	$1,857,153	$2,045,192	$2,351,302	-$3,278,379
Total	$37,611,515	$423,263	$833,459	$1,208,764	$1,664,782	$1,394,654	$1,604,078	$1,857,153	$2,045,192	$2,351,302	$5,054,997
Avoided Costs (Total Resource)											
Demand		$114,120	$229,003	$344,145	$458,989	$0	$0	$0	$0	$0	$8,333,376
Energy		$309,143	$604,456	$864,619	$1,205,793	$1,394,654	$1,604,078	$1,857,153	$2,045,192	$2,351,302	-$3,278,379
Total	$37,611,515	$423,263	$833,459	$1,208,764	$1,664,782	$1,394,654	$1,604,078	$1,857,153	$2,045,192	$2,351,302	$5,054,997
Avoided Costs (Participant)											
Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy		$189,559	$387,458	$593,974	$809,388	$1,033,993	$1,197,221	$1,367,131	$1,543,937	$1,727,861	$1,919,130
Total	$19,775,962	$189,559	$387,458	$593,974	$809,388	$1,033,993	$1,197,221	$1,367,131	$1,543,937	$1,727,861	$1,919,130
COST CALCULATIONS:											
Cost Inputs:											
Implementation		$327,500	$347,545	$364,197	$377,515	$392,295	$407,202	$422,676	$438,738	$455,410	$472,715
Incentives		$589,000	$589,000	$589,000	$589,000	$589,000	$589,000	$589,000	$589,000	$589,000	$589,000
Participant		$589,000	$601,958	$615,201	$628,735	$642,568	$656,704	$671,152	$685,917	$701,007	$716,429
	NPV										
Total Participant Costs	$7,283,502	$589,000	$601,958	$615,201	$628,735	$642,568	$656,704	$671,152	$685,917	$701,007	$716,429
Total RIM Costs	$30,696,412	$1,106,059	$1,324,004	$1,547,171	$1,775,903	$2,015,288	$2,193,424	$2,378,807	$2,571,675	$2,772,271	$2,980,846
Total Utility Costs	$10,920,449	$916,500	$936,545	$953,197	$966,515	$981,295	$996,202	$1,011,676	$1,027,738	$1,044,410	$1,061,715
Total TRC Costs	$11,995,675	$916,500	$949,503	$979,398	$1,006,251	$1,034,863	$1,063,907	$1,093,828	$1,124,655	$1,156,417	$1,189,145

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cumulative Savings (Net System Level)										
Peak Demand Reduction (kW)	5,511	5,937	6,363	6,789	7,215	7,215	7,215	7,215	7,215	7,215
Energy Savings (kWh)	23,668,309	25,418,619	27,168,929	28,919,239	30,669,549	30,669,549	30,669,549	30,669,549	30,669,549	30,669,549
Rates										
Demand ($/kW)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy ($/kWh)	$0.1007	$0.1030	$0.1052	$0.1075	$0.1099	$0.1123	$0.1148	$0.1173	$0.1199	$0.1225
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
BENEFIT CALCULATIONS:										
Avoided Costs (Utility, Ratepayer)										
Demand	$10,054,959	$9,777,079	$9,628,928	$9,485,071	$9,328,406	$8,885,178	$8,596,215	$8,320,024	-$3,179,281	-$5,749,830
Energy	-$3,362,915	-$3,238,276	-$3,356,569	-$3,376,339	-$3,434,541	-$3,285,360	-$3,590,261	-$3,659,464	$4,526,114	$4,745,324
Total	$6,692,044	$6,538,803	$6,272,359	$6,108,732	$5,893,865	$5,599,819	$5,005,954	$4,660,560	$1,346,832	-$1,004,506
Avoided Costs (Total Resource)										
Demand	$10,054,959	$9,777,079	$9,628,928	$9,485,071	$9,328,406	$8,885,178	$8,596,215	$8,320,024	-$3,179,281	-$5,749,830
Energy	-$3,362,915	-$3,238,276	-$3,356,569	-$3,376,339	-$3,434,541	-$3,285,360	-$3,590,261	-$3,659,464	$4,526,114	$4,745,324
Total	$6,692,044	$6,538,803	$6,272,359	$6,108,732	$5,893,865	$5,599,819	$5,005,954	$4,660,560	$1,346,832	-$1,004,506
Avoided Costs (Participant)										
Demand	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy	$2,117,979	$2,324,648	$2,539,386	$2,762,447	$2,994,094	$3,059,964	$3,127,283	$3,196,083	$3,266,397	$3,338,258
Total	$2,117,979	$2,324,648	$2,539,386	$2,762,447	$2,994,094	$3,059,964	$3,127,283	$3,196,083	$3,266,397	$3,338,258
COST CALCULATIONS:										
Cost Inputs:										
Implementation	$490,679	$509,324	$528,679	$548,769	$569,622	$591,267	$613,736	$637,058	$661,266	$686,394
Incentives	$589,000	$589,000	$589,000	$589,000	$589,000	$589,000	$589,000	$589,000	$589,000	$589,000
Participant	$732,191	$748,299	$764,762	$781,586	$798,781	$816,354	$834,314	$852,669	$871,428	$890,599
Total Participant Costs	$732,191	$748,299	$764,762	$781,586	$798,781	$816,354	$834,314	$852,669	$871,428	$890,599
Total RIM Costs	$3,197,658	$3,422,973	$3,657,065	$3,900,216	$4,152,715	$4,240,231	$4,330,018	$4,422,141	$4,516,663	$4,613,651
Total Utility Costs	$1,079,679	$1,098,324	$1,117,679	$1,137,769	$1,158,622	$1,180,267	$1,202,736	$1,226,058	$1,250,266	$1,275,394
Total TRC Costs	$1,222,869	$1,257,623	$1,293,440	$1,330,355	$1,368,403	$1,407,622	$1,448,050	$1,489,727	$1,532,694	$1,576,993

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TABLE 8. RDLC: DETAILED SUMMARY FOR 2006 START YEAR -- 20-YEAR PLANNING HORIZON SUMMARY
PROGRAM NAME: RESIDENTIAL DIRECT LOAD CONTROL
NOT INCLUDED IN ANALYSIS

Discount Rate	8%
General Escalation Rate	2.2%
Measure Lifetime (years)	15

	Benefits	Costs	Net Benefits	B/C Ratio
Participant Test	$0	$0	$0	NA
Ratepayer Impact Measure Test	$32,027,672	$19,468,002	$12,559,670	1.65
Utility Cost Test	$32,027,672	$19,468,002	$12,559,670	1.65
Total Resource Cost Test	$32,027,672	$12,449,979	$19,577,693	2.57

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cumulative Savings (Net System Level)																				
Peak Demand Reduction (kW)	6,161	11,004	14,504	14,654	14,654	14,654	14,654	14,654	14,654	14,654	14,654	0	0	0	0	0	0	0	0	0
Energy Savings (kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rates																				
Demand ($/kW)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Energy ($/kWh)	$0.1130	$0.1154	$0.1180	$0.1206	$0.1232	$0.1259	$0.1287	$0.1315	$0.1344	$0.1374	$0.1404	$0.1435	$0.1467	$0.1499	$0.1532	$0.1566	$0.1600	$0.1635	$0.1671	$0.1708

	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
BENEFIT CALCULATIONS:																					
Avoided Costs (Utility, Ratepayer)																					
Demand		$1,189,896	$2,132,370	$2,815,777	$2,845,812	$0	$0	$0	$0	$0	$24,016,091	$26,737,066	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$32,027,672	$1,189,896	$2,132,370	$2,815,777	$2,845,812	$0	$0	$0	$0	$0	$24,016,091	$26,737,066	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided Costs (Total Resource)																					
Demand		$1,189,896	$2,132,370	$2,815,777	$2,845,812	$0	$0	$0	$0	$0	$24,016,091	$26,737,066	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$32,027,672	$1,189,896	$2,132,370	$2,815,777	$2,845,812	$0	$0	$0	$0	$0	$24,016,091	$26,737,066	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided Costs (Participant)																					
Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
COST CALCULATIONS:																					
Cost Inputs:																					
Implementation		$3,329,133	$2,967,339	$2,538,559	$795,443	$784,307	$814,111	$845,047	$877,159	$910,491	$945,090	$981,003	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incentives		$375,773	$672,003	$906,664	$1,018,132	$1,038,474	$1,054,765	$1,069,842	$1,084,918	$1,099,994	$1,115,071	$1,130,147	$0	$0	$0	$0	$0	$0	$0	$0	$0
Participant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	NPV																				
Total Participant Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total RIM Costs	$19,468,002	$3,704,906	$3,639,341	$3,445,223	$1,813,575	$1,822,781	$1,868,876	$1,914,889	$1,962,077	$2,010,485	$2,060,160	$2,111,150	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Utility Costs	$19,468,002	$3,704,906	$3,639,341	$3,445,223	$1,813,575	$1,822,781	$1,868,876	$1,914,889	$1,962,077	$2,010,485	$2,060,160	$2,111,150	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total TRC Costs	$12,449,979	$3,329,133	$2,967,339	$2,538,559	$795,443	$784,307	$814,111	$845,047	$877,159	$910,491	$945,090	$981,003	$0	$0	$0	$0	$0	$0	$0	$0	$0

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TABLE 9. CIDLC: DETAILED SUMMARY FOR 2006 START YEAR -- 20-YEAR PLANNING HORIZON SUMMARY
PROGRAM NAME: COMMERCIAL INDUSTRIAL DIRECT LOAD CONTROL
NOT INCLUDED IN ANALYSIS

Discount Rate	8%
General Escalation Rate	2.2%
Measure Lifetime (years)	15

	Benefits	Costs	Net Benefits	B/C Ratio
Participant Test	$8,108,692	$0	$8,108,692	NA
Ratepayer Impact Measure Test	$67,188,828	$23,163,985	$44,024,844	2.90
Utility Cost Test	$67,188,828	$15,055,292	$52,133,536	4.46
Total Resource Cost Test	$67,188,828	$6,073,364	$61,115,464	11.06

	NPV	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cumulative Savings (Net System Level)																					
Peak Demand Reduction (kW)		2,983	11,314	17,505	24,598	26,033	28,313	30,339	32,112	33,801	34,926	35,180	0	0	0	0	0	0	0	0	0
Energy Savings (kWh)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rates																					
Demand ($/kW)		$46.00	$47.01	$48.05	$49.10	$50.18	$51.29	$52.42	$53.57	$54.75	$55.95	$57.18	$58.44	$59.73	$61.04	$62.38	$63.76	$65.16	$66.59	$68.06	$69.55
Energy ($/kWh)		$0.0810	$0.0828	$0.0846	$0.0865	$0.0884	$0.0904	$0.0923	$0.0944	$0.0964	$0.0986	$0.1007	$0.1030	$0.1052	$0.1075	$0.1099	$0.1123	$0.1148	$0.1173	$0.1199	$0.1225
		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
BENEFIT CALCULATIONS:																					
Avoided Costs (Utility, Ratepayer)	**NPV**																				
Demand		$576,163	$2,192,384	$3,398,523	$4,776,758	$0	$0	$0	$0	$0	$57,238,702	$64,185,868	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$67,188,828	$576,163	$2,192,384	$3,398,523	$4,776,758	$0	$0	$0	$0	$0	$57,238,702	$64,185,868	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided Costs (Total Resource)																					
Demand		$576,163	$2,192,384	$3,398,523	$4,776,758	$0	$0	$0	$0	$0	$57,238,702	$64,185,868	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$67,188,828	$576,163	$2,192,384	$3,398,523	$4,776,758	$0	$0	$0	$0	$0	$57,238,702	$64,185,868	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided Costs (Participant)																					
Demand		$121,900	$472,471	$747,119	$1,072,907	$1,160,495	$1,289,883	$1,412,609	$1,528,058	$1,643,796	$1,735,912	$1,786,968	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$8,108,692	$121,900	$472,471	$747,119	$1,072,907	$1,160,495	$1,289,883	$1,412,609	$1,528,058	$1,643,796	$1,735,912	$1,786,968	$0	$0	$0	$0	$0	$0	$0	$0	$0
COST CALCULATIONS:																					
Cost Inputs:																					
Implementation		$1,472,361	$1,614,617	$1,265,212	$1,267,311	$224,096	$232,611	$241,451	$250,626	$260,149	$270,035	$280,296	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incentives		$227,550	$690,800	$869,850	$1,191,000	$1,297,575	$1,404,150	$1,510,725	$1,617,300	$1,723,875	$1,794,925	$1,794,925	$0	$0	$0	$0	$0	$0	$0	$0	$0
Participant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	NPV																				
Total Participant Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total RIM Costs	$23,163,985	$1,821,811	$2,777,888	$2,882,182	$3,531,217	$2,682,165	$2,926,644	$3,164,785	$3,395,983	$3,627,821	$3,800,872	$3,862,190	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Utility Costs	$15,055,292	$1,699,911	$2,305,417	$2,135,062	$2,458,311	$1,521,671	$1,636,761	$1,752,176	$1,867,926	$1,984,024	$2,064,960	$2,075,221	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total TRC Costs	$6,073,364	$1,472,361	$1,614,617	$1,265,212	$1,267,311	$224,096	$232,611	$241,451	$250,626	$260,149	$270,035	$280,296	$0	$0	$0	$0	$0	$0	$0	$0	$0

Avoided Capacity and Energy Costs

SCENARIO: Used year-by-year estimates for 20-year forecast horizon (2006-2025), then the escalated levelized value for years beyond.

Electric Avoided Cost	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Demand ($/kW)	$193	$194	$194	$194	$0	$0	$0	$0	$0	$1,639	$1,825	$1,647	$1,513	$1,397	$1,293	$1,231	$1,191	$1,153	-$441	-$797	$769	$786
Average Energy-($/kWh)	$0.117	$0.115	$0.109	$0.114	$0.106	$0.108	$0.111	$0.111	$0.117	-$0.150	-$0.142	-$0.127	-$0.124	-$0.117	-$0.112	-$0.107	-$0.117	-$0.119	$0.148	$0.155	$0.06	$0.064

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Demand ($/kW)	$803	$821	$839	$857	$876	$895	$915	$935	$956	$977	$998	$1,020	$1,043	$1,066	$1,089	$1,113	$1,137	$1,162	$1,188	$1,214	$1,241	$1,268	
Average Energy-($/kWh)	$0.065	$0.066	$0.068	$0.069	$0.071	$0.072	$0.074	$0.076	$0.077	$0.079	$0.081	$0.082	$0.084	$0.086	$0.088	$0.090	$0.092	$0.094	$0.096	$0.098	$0.100	$0.103	

Source: HECO System Planning estimates 5/30/06 (DSM AC 2006A r2.xls) (see below)

Data from DSM AC 2006A r2.xls

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Year-by-year Estimates																				
Demand ($/kW)	193.13	193.78	194.14	194.2	0	0	0	0	0	1638.8	1824.5	1646.8	1513.2	1397.1	1292.8	1231.4	1191.4	1153.1	-440.6	-796.9
Average Energy ($/MWh)	117.4	114.77	109.45	114.48	105.92	107.54	111.43	111.05	116.59	-149.6	-142.1	-127.4	-123.5	-116.8	-112	-107.1	-117.1	-119.3	147.58	154.72
Average Energy ($/kWh)	0.1174	0.1148	0.1094	0.1145	0.1059	0.1075	0.1114	0.111	0.1166	-0.15	-0.142	-0.127	-0.124	-0.117	-0.112	-0.107	-0.117	-0.119	0.1476	0.1547

Avoided Cost (Levelized) -- Used to estimate avoided costs beyond 2025 (2006 values escalated 20 years at annual escalation rate)

Demand ($/kW)	497.5
Average Energy ($/kWh)	0.0402

Lost Margin and Shareholder Incentives for Proposed DSM Programs Under the Current Mechanisms

2006 Energy Efficiency Programs

	Lost Margins	Shareholder Incentives Before Tax	Shareholder Incentives After Tax
CIEE	$891,343	$1,880,449	$1,148,772
CINC	$350,113	$708,433	$432,784
CICR	$412,896	$1,340,425	$818,869
REWH	$162,314	$219,521	$134,106
RNC	$117,722	$424,320	$259,218
E$H	$957,223	$2,008,437	$1,226,960
RLI	$155,655	$391,631	$239,249
Total	**$3,047,266**	**$6,973,215**	**$4,259,958**

2007 Energy Efficiency Programs

	Lost Margins	Shareholder Incentives Before Tax	Shareholder Incentives After Tax
CIEE	$891,343	$1,774,610	$1,084,115
CINC	$350,114	$662,187	$404,532
CICR	$412,896	$1,247,369	$762,022
REWH	$162,314	$210,449	$128,564
RNC	$155,190	$806,333	$492,591
E$H	$587,521	$1,468,723	$897,247
RLI	$155,655	$383,553	$234,314
Total	**$2,715,033**	**$6,553,225**	**$4,003,385**

2008 Energy Efficiency Programs

	Lost Margins	Shareholder Incentives Before Tax	Shareholder Incentives After Tax
CIEE	$891,343	$1,661,694	$1,015,134
CINC	$350,113	$615,871	$376,238
CICR	$412,896	$1,146,906	$700,649
REWH	$162,314	$198,575	$121,310
RNC	$109,931	$677,337	$413,788
E$H	$358,829	$1,259,117	$769,198
RLI	$155,655	$376,659	$230,102
Total	**$2,441,082**	**$5,936,161**	**$3,626,419**

Note: Shareholder Incentives based on Case A avoided cost

REVISED
7/14/2006

CA/HECO-IR-10 **<u>Ref: Final Statement of Position.</u>**

Please provide the electronic spreadsheet files that produce or support the benefit/cost calculations with all formulae and cell references intact and not converted to values, including all input assumptions and the basis for such assumptions. Also, provide a detailed description of what changes were made from the Company's original filing in this Docket.

<u>HECO Response:</u>

Please see HECO's response to CA/HECO-IR-9 for updated Exhibits 7, 8, 10 and 12. Exhibit 8 describes the differences between the updated DSM program budgets and impacts and the Company's original filing in Docket No. 04-0113. The electronic spreadsheet files will be provided under a separate transmittal.

CA/HECO-IR-11 **Ref: Final Statement of Position.**

a. On page 73, does the definition of net system benefits include lost margins and/or shareholder incentives?

b. If so, please explain why the Company thinks it is appropriate for the Company to receive those benefits plus 10% of the net system benefits.

HECO Response:

a. No. The definition of net system benefits does not include lost margins and/or shareholder incentives. As stated on pages 78 - 79 of HECO's FSOP, utility compensation is not a program cost, but is rather the result of the performance-based compensation mechanism. Furthermore, a circular logic would result if utility compensation were to be considered a program cost for calculating net benefits. See HECO's response to RMI/HECO-IR-6.

b. Not applicable.

CA/HECO-IR-12 **Ref: Final Statement of Position.**

a. Does the Company plan to seek lost margins and shareholder incentives on programs administered and implemented by third- parties?

b. If so, please explain in detail why the Company thinks this is appropriate.

HECO Response:

a. HECO does not plan to seek to recover lost margins and shareholder incentives on programs administered and implemented by third-parties. However, in the utility's general rate cases the lost margins due to third-party DSM programs would be embedded in the utility's new base rates as the result of the test year sales estimate. (Note that the third-party administrator, on the other hand, would likely receive compensation for administering its DSM programs.)

b. Not applicable.

DOD/HECO-IR-1-1

Based on the numbers contained in HECO's direct testimony and exhibits, please provide an illustration similar to HECO-1025 of annual reconciliations for a period of five years assuming that HECO does not file another rate case. Also, please state the dollar amounts of lost revenue and incentives that HECO would be collecting each year during this time period.

HECO Response:

In HECO's 2005 TY rate case, Docket No. 04-0113, HECO proposed that three DSM program elements: DSM program expenses, the shortfall in fixed cost recovery, and a return on program costs, be included in base rates. HECO-1025 illustrated the DSM Reconciliation Clause that HECO also proposed in its 2005 HECO rate case in order to reconcile the amounts recovered in base rates with the actual performance of its DSM programs. As a result of the Commission's bifurcation of the consideration of HECO's DSM programs from the 2005 TY rate case to the subject proceeding, the Commission will no longer be considering the inclusion of those three elements in base rates in Docket No. 04-0113 and there would be no reason to implement the DSM Reconciliation Clause. The issue of the reconciliation of DSM program expenses, shortfall, and return on costs, to be included in base rates compared to the actual performance of DSM programs is an issue to be decided by the Commission in the subject proceeding.

If, however, HECO was allowed to continue its existing utility incentive mechanisms, the estimated amounts of lost margins and shareholder incentives for each of the next five years is shown in HECO's response to DOD/HECO-IR-1-2, part b, lines 8 to 13.

DOD/HECO-IR-1-2

Please provide a calculation of the lost revenue and incentives assuming, instead of a three-year rate case cycle:

a. A two-year rate case cycle

b. A five-year rate case cycle.

HECO Response:

A revised Exhibit 13 of HECO's FSOP is shown on page 2 of this response. Line 16 has been corrected to reflect the levels of lost margin shown in lines 1 through 7. In addition, the row header for line 20 has been changed to improve descriptive accuracy. The responses to parts a. and b. below reflect these changes.

a. Please see page 3 of this response.

b. Please see page 4 of this response.

DODIR2 Exh 13 Utility Compensation Scenarios.xls Hawaiian Electric Company, Inc.

Exhibit 13
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Page 2

Utility DSM Compensation
Assuming Rate Case Every 2 Years

Line		Calendar Years					
		1	2[a]	3	4[a]	5	6[a]
	Accrued Lost Margins						
1	1st yr programs	$1.5	$3.0				
2	2nd yr programs		$1.4	$1.4	$1.4		
3	3rd yr programs			$1.2	$2.4		
4	4th yr programs				$1.2	$1.2	$1.2
5	5th yr programs					$1.2	$2.4
6	6th yr programs						$1.2
7	Total Shortfall	$1.5	$4.4	$2.6	$5.0	$2.4	$4.8
8	**Existing Surcharge Mechanism**						
9	Recover in Base Rates			$4.4	$4.4	$9.4	$9.4
10	Surcharge:						
11	Lost Margin Recovery	$1.5	$4.4	$2.6	$5.0	$2.4	$4.8
12	Shareholder Incentive[b]	$7.1	$6.7	$6.0	$6.0	$6.0	$6.0
13	Surcharge Recovery	$8.6	$11.1	$8.6	$11.0	$8.4	$10.8
14	**Rate Case Proposal (Recovered in Base Rates, Shortfall capped at 3 annual years)**						
15	Recover in Base Rates			$4.4	$4.4	$9.4	$9.4
16	Embed in Base Rates	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2
17	Return on Program Costs[c]	$2.1	$2.1	$2.1	$2.1	$2.2	$2.3
18	Total in Base Rates	$7.3	$7.3	$11.7	$11.7	$16.8	$16.9
19							
20	Embed in Base Rates Less Total Shortfall			-$4.5		-$2.8	
21	**CA's Proposal**						
22	Recover in Base Rates			$4.4	$4.4	$9.4	$9.4
23	Surcharge:						
24	Lost Margin Recovery	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
25	Shareholder Incentive	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
26	Surcharge Recovery	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
27	**Company Proposal 1st Alternative, 5% Shared Savings**						
28	Recover in Base Rates			$4.4	$4.4	$9.4	$9.4
29	Surcharge						
30	Fixed Cost Shortfall						
31	5% Shared savings[b]	$3.6	$3.4	$3.0	$3.0	$3.0	$3.0
32	Surcharge Recovery	$3.6	$3.4	$3.0	$3.0	$3.0	$3.0
33	**Company Proposal 2nd Alternative 1-year Shortfall Recovery + 15% of Program Costs**						
34	Recover in Base Rates			$4.4	$4.4	$9.4	$9.4
35	Surcharge						
36	1-yr Fixed Cost Shortfall	$1.5	$2.9	$2.6	$2.4	$2.4	$2.4
37	15% of Program Cost[c]	$2.1	$2.1	$2.1	$2.1	$2.2	$2.3
38	Surcharge Recovery	$3.6	$5.0	$4.7	$4.5	$4.6	$4.7
39	Capped at $4.0 million	$3.6	$4.0	$4.0	$4.0	$4.0	$4.0

Notes:

a. Rate case year, new rates effective in the following year.

b. Existing shared savings mechanism.
   Updated avoided energy and capacity costs, Program costs, using 2006 fuel price forecast.

c. Updated program costs, excluding load management.

DOD/HECO-IR-1-3

With respect to HECO-1019 please state the following:

a. Do the amounts shown on Lines 1 through 4 represent expenses or capital investment?

b. Is the rate of return shown on Line 5 a rate of return on capital investment or is it a mark-up or margin on proposed expenses?

HECO Response:

a. The amounts represent DSM program expenses.

b. The rate of return is similar to a mark-up on DSM program expenses.

October 5, 2001

Robert A. Alm
Senior Vice President
Public Affairs

2001 OCT -5 P 3:45
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building
465 South King Street, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 00-0169
<u>HECO C&I DSM Program</u>

This letter incorporates the oral agreement that Hawaiian Electric Company, Inc. ("HECO") and the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") reached prior to the status conference on September 21, 2001 and finalized on October 3, 2001, related to the issues in this proceeding regarding the proposed Commercial and Industrial Demand-Side Management Program ("C&I DSM Program").

This agreement was reached because of the substantial economic uncertainty facing our nation, our state and HECO in the immediate future, as a result of the events of September 11, 2001. This is addressed in Attachment A, which contains confidential financial information[1], and is submitted under protective order.

In light of the information contained in Attachment A, HECO and the Consumer Advocate have agreed to the temporary continuation of HECO's three existing C&I DSM programs[2] in place of approval of a new consolidated C&I DSM program for five years (as requested in Docket No. 00-0169), until HECO's next rate case (which HECO has committed to file within 2 to 3 years using a 2003 or 2004 test year in accordance with §6-61-87(4)(A) and (B) of the Hawaii Administrative Rules ("HAR")). In return, HECO has agreed to cap recovery of lost margins and shareholder incentives based on the existing surcharge mechanism, so that such recovery will <u>not</u> allow the Company to exceed its current authorized rate of return on rate

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1 Disclosure of earnings estimates (especially net income estimates) could trigger requirements under the rules and guidelines of the Securities and Exchange Commission ("SEC") and/or the New York Stock Exchange that information that would be meaningful to an investor (such as earnings estimates) be released to all investors, if the information is disclosed beyond a limited number of "insiders." Persons having access to such information as a result of their government employment may be deemed 'insiders" for purposes of the SEC's insider trading prohibitions.

2 HECO's three existing C&I DSM programs are the Commercial and Industrial New Construction ("CINC") Program approved in Docket No. 94-0010, the Commercial and Industrial Customized Rebate ("CICR") Program approved in Docket No. 94-0011 and the Commercial and Industrial Energy Efficiency ("CIEE") Program approved in Docket No. 94-0012. HECO currently has an extension of its existing three C&I DSM programs, through the end of December 2001.

DOD/HECO-IR-1-5

Please provide a complete copy of the report referenced at Lines 5 through 17 on Page 27 of HECO T-12.

<u>HECO Response:</u>

The requested document is voluminous. A copy can be made available for inspection at HECO's Regulatory Affairs office. Please contact Dan Brown at 543-4795 to arrange for inspection. To also facilitate the review of the document, HECO will provide a PDF of the document on a CD.

DOD/HECO-IR-1-7

Please provide the complete document from which the quotation beginning at Line 13 on Page 38 of HECO T-12 is taken. Include the date the document was created or that the statement by Mr. Rowe was made.

HECO Response:

The requested document is voluminous. A copy can be made available for inspection at HECO's Regulatory Affairs office. Please contact Dan Brown at 543-4795 to arrange for inspection. To also facilitate the review of the document, HECO will provide a PDF of the document on a CD.

DOD/HECO-IR-1-8

Please provide a copy of the Statement of Position of the Division of Consumer Advocacy dated June 1, 2001 in Docket No. 00-0169, referenced on Page 35 of HECO T-12.

HECO Response:

The requested document is voluminous. A copy can be made available for inspection at HECO's Regulatory Affairs office. Please contact Dan Brown at 543-4795 to arrange for inspection. To also facilitate the review of the document, HECO will provide a PDF of the document on a CD.

DOD/HECO-IR-1-9

Concerning Page 9 of HECO T-11, the answer beginning at Line 16 provides certain incremental savings. Please provide the base period against which the incremental savings are estimated.

HECO Response:

The base year for the analysis was the test year of 2005. Note that in the current proceeding, the base year has shifted to 2006 due to the time lag between the filing of HECO T-11 and the analysis supporting the current Docket.

DOD/HECO-IR-1-10

Concerning Page 9 of HECO T-11, the answer beginning on Line 24, please state the base to which the 2003 reduced energy consumption and demand is compared.

HECO Response:

The 2003 values reported in HECO T-11 represent savings in that year (i.e., incremental savings). The values reported for 2005 also represent savings in that year. Because both years (2003 and 2005) represented incremental savings, comparisons between the two years were made in that context.

DOD/HECO-IR-1-11

On Page 11 of HECO T-11, the results of the various benefit/cost measures for the programs in total are reported. Please state whether the utility incentives (the 15% mark-up) are included in the calculation of any of these ratios, and if so state which ones. If they have been omitted, please provide ratios (for the programs in total and each individual program) including the 15% utility incentive.

HECO Response:

The benefit cost ratios on Page 11 of HECO T-11 reflect the 15% return on cost. However, many of the DSM program input assumptions have changed from Docket No. 04-0113 (e.g., updated HECO FSOP, Exhibits 7, 8, 10 and 12, in CA/HECO-IR-9). The B/C ratios for the updated programs are reported in the table below that summarizes the cost-effectiveness test results that are shown in HECO's response to CA/HECO-IR-9. For illustrative purposes the test results reflect one (Alternative No. 2) of the three utility compensation proposals being made by HECO in its FSOP as an example of the effect of including utility compensation.

Benefit/Cost Tests for Docket Programs with 15% Return on Cost

Program	B/C Ratio			
	TRC	RIM	Utility	Participant
1. Commercial and Industrial Energy Efficiency	1.68	0.48	3.82	3.69
2. Commercial and Industrial New Construction	1.49	0.44	3.04	3.84
3. Commercial and Industrial Custom Rebates	0.97	0.49	4.46	2.05
4. Energy Solutions for the Home	2.92	1.73	6.16	1.61
5. Residential Efficient Water Heating Program	0.75	0.70	1.41	0.76
6. Residential New Construction Program	1.40	0.91	2.03	1.19
7. Residential Low Income	3.14	1.23	3.44	2.72
8. Residential Direct Load Control	2.57	1.65	1.65	NA
9. Commerical Industrial Direct Load Control	11.06	2.90	4.46	NA
Overall	**1.66**	**0.73**	**3.25**	**2.38**

DOD/HECO-IR-1-12

With respect to the CIEE program, HECO T-11, Page 14 states that the program has resulted in a net reduction of 10.189 MW of demand and 72,609 MWh of energy since its inception. HECO WP-1104, Page 3, shows 2003 actual results as 1.264 net MW of peak demand and 9,820 MWh of energy. Please reconcile these two statements and explain the difference in the measurement and in the reporting.

<u>HECO Response:</u>

The CIEE program savings reported in HECO T-11 Page 14 represent annualized savings in calendar year 2004 from measures installed between 1996 and 2003. Under the 2003 Actuals column, HECO-WP-1104 shows annualized savings in 2003 for CIEE program measures installed in 2003.

DOD/HECO-IR-1-13

Referring to HECO T-11, Page 14, Line 21, the 2005 goals for the CIEE program reported there are the same as what is shown on Page 3 of HECO-WP-1104. State what the cumulative savings by 2009 represent. Is this the sum of the savings in each of the years 2005 through 2009, or is this the annualized savings expected to be achieved by 2009?

HECO Response:

The cumulative savings by 2009 of 10.1 MW and 69,674 MWh represent the annualized savings in the year 2009 from measures installed between 2005 through 2009.

DOD/HECO-IR-1-14

With respect to HECO-WP-1104, Page 3, please explain if there is any relationship between the kW and MWh savings in the 2003 actual column and in the 2005 test year estimate column. If the 2003 is included in the 2005, please so state, or if not, then state that it is not. Also, do the amounts shown in each of the two columns represent the savings attributable to all participants in the program in those time frames, or do these relate just to the additional participants expected to be in the programs? Please explain.

HECO Response:

There is no relationship between the 2003 actual values and the 2005 projections in terms of measures installed. As stated in HECO's response to DOD/HECO-IR-12, HECO-WP-1104, under the 2003 Actuals column, shows annualized savings in 2003 for CIEE program measures installed in 2003. The savings shown under the 2005 Test Year Estimate column are the annualized savings in the 2005 test year resulting from measures installed in 2005. Thus, 2003 measure impacts are not included in 2005 measure impacts.

The amounts shown in the 2003 Actuals column, and in the 2005 Test Year Estimate column, represent savings attributable to those participants who installed measures in 2003 and are expected to install measures in TY 2005, respectively.

DOD/HECO-IR-1-15

With regard to the response to the three preceding questions concerning CIEE, would the same general answers (with different numbers) apply to similar questions about all of the other programs? If not, please explain.

HECO Response:

Yes. The response to DOD/HECO-IR-1-12 to 14 apply to all of the proposed programs in this proceeding that are continuations of existing programs that were in effect in 2003 (CIEE, CINC, CICR, REWH, and RNC). Since the other programs (ESH, RLI, RDLC and CIDLC) were not in place during the 2003 reporting year, such comparisons could not be made.

DOD/HECO-IR-1-16

Referring to HECO's Final Statement of Position (FSOP), pages 78-80, please clarify whether the alternative utility compensation proposals discussed there and illustrated on the attached Exhibit 13 should be construed as replacing the proposals which HECO made in its initial filing in the rate case from which these DSM issues were extracted.

HECO Response:

HECO has made three utility compensation proposals, one which HECO described in direct testimony in Docket No. 04-0113, and 2 alternative proposals described on pages 78 and 79 of its FSOP. HECO is making these three proposals in order to facilitate discussion that may lead to substantial agreement on one of the three proposals or some version of the three proposals. Should DSM expenses and utility compensation be approved for inclusion in base rates in the next rate case, HECO also proposes that during the period until the next rate case, that HECO recover the DSM expenses and utility compensation through a DSM surcharge. HECO strongly believes that utility compensation in one form or another is necessary for the aggressive pursuit of demand-side resources and HECO is willing to consider alternative compensation mechanisms as well as different levels of compensation provided that the incentives are performance-based, i.e., are allowed to rise or fall depending on the actual energy and demand reductions realized each year. See also HECO responses to DOD/HECO-IR-1-2, DOD/HECO-IR-1-17, RMI/HECO-IR-19, and HSEA/HECO-FSOP-7.

DOD/HECO-IR-1-18

With respect to page 78 of the FSOP, the second full paragraph, please explain in detail why HECO would propose to exclude measurement and evaluation costs in calculating the shareholder incentive.

HECO Response:

HECO proposes that an independent third-party evaluator selected by the Commission be responsible for periodically conducting an evaluation of the utility and non-utility DSM programs and program impacts. The evaluation would be similar to the program impact evaluation currently conducted by a third-party, KEMA, Inc., hired by HECO. The evaluation is conducted approximately every three years. The independent third-party would be selected by the Commission through an RFP process from lists provided by both the utility and non-utility administrators.

Since under this proposal, the Commission would be overseeing and paying for the evaluation, the costs incurred for the evaluation should not be included in calculating the shareholder incentive.

HSEA/HECO-FSOP-1 Ref HECO FSOP, page 16, footnote 8:

HECO states that its cost of energy efficiency is actually less than 2 cents/kWh. The calculation is function of the estimated useful life of the equipment, i.e. 15 years. In regard to the REWH and RNC solar water heating programs, what information or data was used to determine the estimated fifteen year system life?

HECO Response:

The fifteen year life for a solar water heating system was developed in 1993 during the design of the REWH and RNC programs. HECO relied primarily on ASHRAE, 1990 for typical life expectancy for its DSM measures, (see Appendix A: Technology Assessment Sheets, Demand-Side Management Resource Assessment Final Report May 7, 1993). This information was also provided to HECO's DSM Advisory Group members for review and further refinement as necessary. The useful life of a solar system installed under HECO REWH and RNC programs has not been further evaluated, however, HECO believes the 15-year useful life remains reasonable.

HSEA/HECO-FSOP-2 Ref HECO FSOP, p. 29

HECO states that non-quantifiable benefits of solar water heating – clean, renewable, customer equity, in harmony with state energy objectives, etc. - are not included in the calculation of cost-effectiveness.

a. Does HECO mean that these benefits cannot be quantified, or have not been quantified, for the purpose of establishing a more accurate TRC value?

b. How does HECO weight such "qualitative" benefits in their determination of overall program cost-effectiveness?

HECO Response:

a. Non-quantifiable benefits of solar water heating have not been quantified for the purpose of calculating the TRC Test ratio. HECO uses the definition of the TRC Test described in the California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects and therefore only includes certain benefits and costs as defined by the manual in the calculation of the TRC results. In its Decision and Order No. 11523 the Commission recognized the difficulty in accurately analyzing non-quantifiable benefits. In discussing the disagreement between the parties to that Docket to the concept of quantifying non-quantifiable benefits the Commission states: "(a)t the center of the controversy is whether any assigned quantitative value truly measures the impact that is being sought to be assessed." (See page 22, Decision and Order No. 11523, Docket No. 6617.) Consequently, the Commission ordered: "(i)mpacts that cannot be reasonably and feasibly valued in dollar terms are to be qualitatively described."

b. There is not a formal process for weighting such qualitative benefits in the overall program cost-effectiveness. In its annual A&S and M&E reports, HECO reports the cost-effectiveness of each of its DSM programs without any non-quantifiable benefits, but describes those benefits in qualitative terms.

In general, HECO believes that its DSM programs should all have positive net benefits according to both the UC and TRC test perspectives to be considered "cost-effective". However, the overall determination of cost-effectiveness in the IRP process should take into account all of the goals and objectives of IRP (including the availability of non-quantifiable benefits, the impact of the programs on the utility's financial integrity, supporting Hawaii's State energy objectives and the rate impact of the programs). The determination of cost-effectiveness in IRP should consider both quantitative benefits and costs (which are reflected in the benefit-cost ratios) and qualitative benefits and costs (which are not reflected in the benefit-cost ratios). DSM programs provide significant qualitative benefits, which help achieve the objectives of HECO's IRP. Solar water heaters utilize an environmentally clean, renewable energy resource. In addition, the solar water heating component of the residential DSM programs is a major contributor to meeting the State's renewable energy objective.

HSEA/HECO-FSOP-4 Ref HECO FSOP, p, 49

With the exception of a proposed increase in the RNC rebates for solar water heating systems, HECO has offered no other changes to the current RNC programs. The current RNC "tank and timer" program rebate is $280. Subsequent to installation the homeowner receives a $5 per month bill credit during the lifetime of the measure (or until the homeowner opts for another water heating option). Over the 15 year estimated equipment life HECO will have offered rebates and credits for this measure equal to $1,180 (cf. current $750 one time rebate for solar water heating).

High efficiency 80 gallon electric water heaters are being offered in volume to homebuilders at $375, providing a net out of pocket builder cost for this option after RNC rebates of $95 (HECO provides the timer at no cost to the builder). In relation to RNC solar rebates, which incent both energy and capacity savings, please explain how the company justifies rebates and credits of this magnitude for this specific load management measure (i.e. the measure provides no appreciable energy savings).

HECO Response:

HECO does not agree with HSEA's contention that the "tank and timer" measure does not provide any appreciable energy savings. The "tank and timer" measure for which HECO provides rebates under the RNC program consists of a higher than standard efficiency 80 gallon or larger electric water heater coupled with a load management timer that effectively turns the water heater off during the entire evening peak period of 5:00 p.m. to 9:00 p.m. As such, the "tank and timer" measure does provide some energy savings due to the higher than standard efficiency water heater and provides substantial peak demand reductions resulting from the load control timer. Since program inception, HECO has encouraged the installation of over 5,000 "tank and timers". These measures contribute 2.8 MW of peak load reduction and 1,500 MWh of annual energy savings. Based on HECO current reserve margin shortfall it would not make sense to discontinue rebates for this measure.

HECO also believes that customer equity is an issue of concern. As such, HECO recognizes that not all new residential developments can install solar water heating systems as

b. No. HECO has paid an "all-electric" incentive to home developers the costs of which are below-the-line. However, late last year HECO halted new commitments to developers for these incentives. Under the "all-electric" incentive developers were free to install either tank and timer, high efficiency electric water heaters, or solar water heating and the incentive did not favor one electric water heating technology over the others.

mechanism to compensate the utility for the recovery of fixed costs foregone due to sales lost as a result of the aggressive implementation of DSM programs. Moreover, HECO believes that a third-party DSM service provider would also require compensation beyond simple program cost recovery. Finally, appropriate alignment of financial incentives with well performing energy efficiency programs is simply good public policy.

In addition, as stated in its response to DOD/HECO-IR-1-16, HECO is making alternative proposals with respect to utility compensation for implementing DSM programs in order to facilitate discussion that may lead to substantial agreement on one of the three proposals or some version of the three proposals. Also, HECO is interested in reviewing the responses of the parties to its information requests with respect to the issue of utility compensation for implementing DSM programs, and is willing to engage in settlement discussion meetings with the parties on the issue of utility compensation, as well as other issues in the proceeding, prior to the August 2006 panel hearings. See also HECO responses to DOD/HECO-IR-1-2, DOD/HECO-IR-1-17, and RMI/HECO-IR-19.

HSEA/HECO-FSOP-8 Ref HECO FSOP, p. 56

The Company states that without an adjustment mechanism the utility is financially worse off when it implements DSM programs. In footnote 8, page 16, HECO states that energy efficiency at 2 cents/kWh is less expensive than any supply side option currently available in the State. If DSM is **less** expensive than all other supply side options, please explain why the utility is worse off choosing DSM over generation?

HECO Response:

Under current rate making policies the utility is allowed to earn a fair return on its capital investments in generation. In contrast, when a utility promotes effective energy efficiency DSM programs,

1) revenue is reduced by more than the reduction in variable costs due to lower sales, and

2) without utility compensation, the energy efficiency programs fail to earn a return at the same time they defer those capital investments in generation upon which the utility can earn a fair return.

Energy sales are reduced from the levels that otherwise would have occurred without DSM. The reduced levels of energy use result in reduced costs to supply the energy, but also result in a larger reduction in revenue to the utility. Embedded in that revenue is not only the fair return allowed by the Commission on the utility's investment in generation, but also some contribution to the utility's fixed costs to serve its customers. Consequently, if a utility implements effective energy efficiency programs without a utility incentive, not only is there a potential foregone opportunity to invest that money in an endeavor that would produce a fair return, but it also contributes to an erosion of the utility's revenue to offset its fixed costs and maintain its level of profitability.

RMI/HECO-IR-1 Re: HECO FSOP at page 13: "Free-riders" in RPS

Does HECO consider impacts of measures installed by "free-riders" to be electrical energy savings brought about by its DSM programs?

HECO Response:

Yes, but only to the extent that those energy savings were realized as a result of an energy conservation measure installation that received a HECO DSM customer incentive. As a measure installed under the DSM program the energy savings reduces the oil consumed by electricity generators and promotes energy self sufficiency. However, HECO does not claim free-riders when calculating lost margins or shareholder incentives.

HECO's evaluation consultant, KEMA, Inc., has conducted three cycles of DSM program impact evaluations which assess individual DSM measure energy and demand savings and the level of free-ridership. HECO is in the process of obtaining input from the Consumer Advocate in order to finalize the survey instrument to conduct the net-to-gross study for the third cycle impact evaluation study. This net-to-gross study will assess the level of free-ridership for measures installed in program years 2005 through 2007.

RMI/HECO-IR-3 Re: HECO FSOP at pages 30-31, outside positions.

Please provide the percentage of current positions for HECO, MECO and HELCO directly related to DSM administration that are contract employees from outside firms.

HECO Response:

See below:

	Current Positions	Contract Positions	Contract as % of Current
HECO	18	8	44%
MECO	8	6	75%
HELCO	2	2	100%
Total	28	16	57%

RMI/HECO-IR-4 Re: HECO FSOP at page 46: scope of discussion.

Please indicate the extent to which HECO's discussion of DSM incentive mechanisms provided "in more detail in Issue #8" also apply to MECO and HELCO or more generally as statewide issues.

HECO Response:

The DSM utility incentive mechanisms proposed by HECO would also apply to MECO and HELCO.

RMI/HECO-IR-5 Re: HECO FSOP at page 78: "Utility compensation should also be excluded from program costs."

Does HECO hold that utility "compensation" (DSM utility incentives) are not costs to ratepayers associated with DSM implementation?

HECO Response:

DSM utility compensation is paid for by ratepayers, but should not be costs included in the calculation of shared savings. This would be akin to calculating the profits of a business for income statement purposes and then recalculating the income statement by increasing expenses by those same profits simply because the profits are paid for by its customers. The program costs included in HECO's proposed Modified Utility Cost Test shared savings mechanism should conform to the cost elements included in the *California Standard Practice Manual: Economic Analysis of Demand-side Programs and Project.*

RMI/HECO-IR-8 Re: HECO FSOP Exhibits 7 and 8: Clarification re: "Incentives"
In both of these exhibits there are numerous references to "incentives" that appear to refer exclusively to incentives to customer program participants.

Please indicate whether this is the case and identify all references to incentives to utility incentives, if any, in the exhibits.

HECO Response:

The term "incentives" in the context of Exhibits 7 and 8 refer to exclusively to incentives to customer program participants.

RMI/HECO-IR-9 re: HECO FSOP Exhibits 7 and 8: Federal standards.

Are the latest federal minimum standards air conditioner efficiency and motor efficiency used in determining program impacts throughout these two updated exhibits? Please identify what standards are used to establish the base case air conditioner and motor energy consumption performance.

HECO Response:

The latest federal minimum standards for air conditioning and motor efficiencies are included in the impact analysis that supports the various programs. For example:

- Room Air Conditioner (less than 1-ton unit): Minimum EER=9.8
- Central Air Conditioner: Minimum SEER=13
- Package Air Cooled Split System (larger commercial type): EER=9.5
- Package Air Cooled Split System (smaller commercial type): EER=10.3
- Package Water Cooled Split System (all commercial types): EER=11.0
- Water Cooled Centrifugal Chillers (very large type): Min. Efficiency=0.60 kW/ton
- Water Cooled Centrifugal Chillers (medium and large types):
  Min. Efficiency=0.68 kW/ton
- Motors: Premium efficiency classification according to NEMA

RMI/HECO-IR-11 Re: HECO FSOP Exhibit 10, p.2: Assumed capital costs.

a. Please indicate the source, components and calculation of the discount rate used in the exhibit.

b. Please provide the most recent components, proportions and returns for HECO's capital structure (short and long term debt, preferred and common equity) proposed by HECO, the Consumer Advocate and/or recognized in the Commission's interim order in HECO's rate case (Docket No. 04-0113).

HECO Response:

a. The discount rate of 8.09% used for computation of the net present value components of the benefit/cost ratios were derived from the HECO IRP-3 analysis.

b. See the attached illustration of the composite cost of capital of 8.66% that was deemed appropriate and reasonable, for interim decision purposes pending a final decision in the docket, by the Commission in Interim Decision and Order No. 22050 in Docket No. 04-0113.

did evaluate the reasonableness of HECO's Energy Efficiency programs (see Section 6 and 11.6.3), using the assumptions available at the time. Further, Chapter 14 of the IRP-3, *Updated Information and its Effect on the Analyses,* does indicate potential changes in DSM impacts (see 14.1.3, *Enhanced Energy Efficiency Demand-Side Management*).

b. The "Demand ($/kW)" values shown on Exhibit 10, page 12, originate from the workpaper provided as Exhibit 12, page 6. The revenue requirements for two plans were calculated, "With Future EE DSM" and "No Future EE DSM". The difference in revenue requirements between plans was then decomposed into "Avoided Production Costs" (Exhibit 12, page 5, Column 7) and "Avoided Capital and Fixed O&M Costs" (Exhibit 12, Page 6, Column 17). The "Avoided Capital and Fixed O&M Costs" were then converted to a $/kW rate using the "EE DSM Peak Reduction" (Exhibit 12, Page 6, Column 20). The revenue requirement calculations do reflect return of and return on investments using a composite weighted average cost of capital of 9.560% (8.579% after-tax weighted average) assumption. HECO assumes that the "Economic Carrying Charge" in question refers to a value that may be reported in an optional diagnostic report (possibly from PROVIEW Diagnostic #6). HECO does not use this diagnostic (from a single plan) as a basis for its estimation of the DSM avoided cost. Rather, the difference in cost between two plans is derived, as explained above.

c. The "Demand ($/kW)" values shown on Exhibit 10, page 12, originate from the workpaper provided as Exhibit 12, page 6. The components include capital costs and fixed operations and maintenance costs. Items such as depreciation, return on investment (interest expense and preferred and common returns), income and revenue taxes, and other factors which

series, except that some of the numbers are show as $/Mwh rather than $/kwh. The middle series of numbers are an old series of avoided cost information not used in the analysis.

RMI/HECO-IR-13 Re: HECO FSOP Exhibit 10, p.12: Avoided Capacity Costs.

Please provide the following information to the extent it is available:

a. What amount (annually or NPV) of the avoided demand (capacity) costs in the no-DSM case are attributable to return on equity for new supply resources? Clarify whether this amount is stated before or after taxes.

b. What amount of the avoided demand (capacity) costs in the DSM portfolio case are attributable to return on equity for new supply resources?

c. By what amount (annually or NPV) does the DSM portfolio reduce HECO's return on equity for new supply resources?

HECO Response:

a. The assumed rate of return on common equity is 12% (return to shareholders after corporate income taxes), for both the "with EE DSM" and "without EE DSM" case. HECO cannot readily quantify this in year-by-year dollars. The capital structure and individual cost element assumptions utilized in the DSM avoided cost analysis are as follows:

	Weight	Rate
ST Debt	3%	6%
LT Debt	36%	6.5%
Preferred	7%	8%
Common	54%	12%

Composite	9.560%
After-Tax Composite	8.579%

b. Please see HECO response to sub-part a. above.

c. HECO has not analyzed the impact of the DSM portfolio on its equity returns. The avoided capacity revenue requirements assume a 12% rate of return on equity in both the "with EE DSM" and "without EE DSM" cases.

RMI/HECO-IR-14 Re: HECO FSOP Exhibit 10, p.12: Virtual DG avoided costs.

a. Are the avoided demand costs of $194 per kilowatt for years 2006 through 2009 the costs associated with "Virtual DG" referenced in HECO FSOP Exhibit 12 at pages 2-3? If not, please explain the source of these avoided costs.

b. Do the avoided demand costs for these years represent actual avoided cost streams or do they represent the value of system reliability for these years?

c. Please explain how these avoided costs were derived.

d. Are these costs different in any way than the avoided demand costs indicated for the years 2015 and thereafter? Please explain.

e. Do the values of $0 for the years 2010 through 2014 for avoided demand costs indicate that there is no capacity or reliability value provided by the DSM programs in these years? Please explain.

HECO Response:

a. Yes

b. The avoided demand costs are estimates for avoided cost streams, based on a proxy (the "Virtual DG", as described on pages 2-3 of Exhibit 12). These estimates are not intended to value system reliability for those years.

c. These proxy costs for Virtual DG were based on HECO's experience with utility-sited distributed generation, and include estimates for lease rent, capital improvements, and operations and maintenance such as telecommunications, labor, security, environmental, etc.

d. Yes, the methodology for using Virtual DG to estimate Demand ($/kW) avoided costs is only used for 2006 through 2009. The Demand ($/kW) for other years -- such as 2015 and beyond -- is based on a scenario which defers a coal unit. As illustrated by the scenario on Exhibit 12, page 4, without Energy Efficiency DSM, the supply-side coal unit would be needed in 2015 rather than 2024. Since this deferral value is due to the Energy Efficiency

RMI/HECO-IR-15 Re: HECO FSOP Exhibit 12, p.1-3: Clarification of "Scenario A"
Several references are made to "Scenario A".

Does this scenario refer to the DSM case, the no-DSM case or both? Are there other scenarios? What are the results of the other scenarios? Please clarify.

HECO Response:

"Scenario A" refers to both the DSM case and no-DSM case.

In the process of developing resource plans, the Company develops innumerable scenarios to explore the uncertainty surrounding the input assumptions. However, for the purpose of developing a basis for the EE Docket DSM avoided capacity and energy costs, Scenario A was deemed to be a reasonable depiction of a likely resource plan.

Please refer to the attached 180 MW Atmospheric Fluidized Bed Combustion Unit Information Form, which was provided in HECO's IRP-3 at Appendix O-170. HECO updated the estimate for Total Capital Cost to $557 Million in 2006 dollars (IRP-3 estimated $492 in 2003 dollars), and the Mature Forced Outage Rate to 2 percent (IRP-3 estimated 6%).

d. Please see the response to RMI IR-14, sub-part c.

pursuing development of DG options such as dispatchable standby generation due to the inherent value that such options may provide to HECO and its ratepayers.

RMI/HECO-IR-18 Re: HECO FSOP Exhibit 12, p.11: Derivation of utility incentives. The tables on page 11 show lost margins and shareholder incentives for HECO's proposed DSM programs under HECO's original mechanisms.

a. Does HECO provide anywhere in its filings in this docket similar information showing annual lost margins and shareholder incentives under any of its mechanisms proposed in this docket? Please indicate where this information has been provided.

b. Does HECO provide updated versions of the exhibits to T-10 filed in Docket No. 04-0113 showing how its updated proposals for lost margins and shareholder incentives would be calculated, implemented and reconciled? Please indicate where this information has been provided.

HECO Response:

a. Yes. The annual utility compensation levels for HECO's two alternatives described on pages 78 and 79 of its FSOP are shown in Exhibit 13, on lines 27 through 39. Exhibit 13 has been updated in DOD/HECO-IR-1-2, page 2.

b. Yes, the annual utility compensation levels for utility incentive proposed by HECO in Docket No. 04-0113 are shown in Exhibit 13, lines 14 through 20. Exhibit 13 has been updated in DOD/HECO-IR-1-2, page 2.

RMI/HECO-IR-19 Re: HECO FSOP Exhibit 13: Utility incentive projections.

a. Please clarify what is proposed in "Company Proposal 1st Alternative…" and "Company Proposal 2nd Alternative…". Do these refer to specific alternatives described in HECO's FSOP?

b. Is it intentional that there are no fixed cost shortfall amounts entered on line 30?

<u>HECO Response:</u>

a. Yes, the proposals refer to the alternatives described on pages 78 and 79 of HECO's FSOP. HECO has made three utility compensation proposals, one which HECO described in direct testimony in Docket No. 04-0113, and 2 alternative proposals described on pages 78 and 79 of its FSOP. HECO is making these three proposals in order to facilitate discussion that may lead to substantial agreement on one of the three proposals or some version of the three proposals. The two alternative proposals provide approximately the same level of incentive of about $3 to $4 million per year. Please also see HECO's responses to DOD/HECO-IR-1-2, DOD/HECO-IR-1-16, DOD/HECO-IR-1-17, and HSEA/HECO-FSOP-7.

b. Yes, HECO's 1st utility compensation Alternative does not include the recovery of fixed cost shortfalls between rate cases. The shortfalls are recovered through base rates in a general rate case when the impact of energy savings resulting from DSM programs is included in the test year sales estimate.

RMI/HECO-IR-22

Please provide for each year from 1996 through 2005 for each HECO customer class:

a. the base energy rates (by block where applicable)

b. the base fuel energy rates

c. the average marginal cost of delivered energy (broken down by components as in HECO-WP-2217 at pages 90 – 95.)

HECO Response:

a. Schedule R

Effective 01/01/96 Base Fuel Energy Charge 3.514 cents per kWh

Non-Fuel Energy Charge 7.7610 cents per kWh

Effective 01/01/97 Non-Fuel Energy Charge 7.7814 cents per kWh

Schedule G

Effective 01/01/96 Energy Charge 11.1775 cents per kWh

Effective 01/01/97 Energy Charge 11.1570 cents per kWh

Schedule J

Effective 01/01/96

First 200 kWh/mo/billed kW 8.7054 cents per kWh

Next 200 kWh/mo/billed kW 7.5574 cents per kWh

All over 400 kWh/mo/billed kW 6.5286 cents per kWh

Effective 01/01/97

First 200 kWh/mo/billed kW 8.6900 cents per kWh

Next 200 kWh/mo/billed kW 7.5419 cents per kWh

All over 400 kWh/mo/billed kW 6.5130 cents per kWh

HECO Response continued:

Schedule H

Effective 01/01/96	Energy Charge	7.7296 cents per kWh
Effective 01/01/97	Energy Charge	7.7422 cents per kWh

Schedule P (all PS, PP, PT)

Effective 01/01/96

First 200 kWh/mo/billed kW	7.2136 cents per kWh
Next 200 kWh/mo/billed kW	6.4152 cents per kWh
All over 400 kWh/mo/billed kW	6.1056 cents per kWh

Effective 01/01/97 to 05/31/01

First 200 kWh/mo/billed kW	7.2087 cents per kWh
Next 200 kWh/mo/billed kW	6.4104 cents per kWh
All over 400 kWh/mo/billed kW	6.1010 cents per kWh

Schedule PS

Effective 06/01/01

First 200 kWh/mo/billed kW	7.2087 cents per kWh
Next 200 kWh/mo/billed kW	6.4104 cents per kWh
All over 400 kWh/mo/billed kW	6.1010 cents per kWh

HREA/HECO-IR-2 Also on page 9, HECO states the following:

> "HECO supports goals for energy efficiency and has developed an estimate for the amount of energy efficiency that the Company intends to achieve on Oahu over a five year action plan implementation period, provided HECO receives approval to implement its proposed DSM programs ..."

HREA observes that HECO had not included certain DSM technologies in its IRP, which we believe can provide significantly benefits, e.g., solar air conditioning (SAC) systems, seawater air conditioning (SWAC) district cooling systems, and customer-sited, electricity-generating renewables, such as PV and wind. Can HREA get HECO's support to include these technologies in its IRP? If not, why not?

HECO Response:

HECO supports all demand-side technologies that can reduce the use of electrical energy by the customer. This includes seawater air conditioning district cooling systems, which may be the recipient of customer rebates under HECO's Commercial and Industrial Customized Rebate Program. HECO also supports electricity–generating renewables, such as PV and wind in its IRP as indicated in its IRP-3 report, figure 1.17-1, "Final Preferred Plan", page 1-24. However, because these latter technologies are supply-side technologies rather than demand-side measures, they are not eligible for customer rebates under HECO's DSM programs.

HREA/HECO-IR-3 On page 10, HECO states the following:

> "The energy efficiency DSM program goals should also be achievable; otherwise the goals quickly become irrelevant. Maximum achievable potential ("MAP") represents the maximum amount of energy efficiency that is obtainable from measures covered by the utilities' DSM programs. In order to achieve the MAP the customer incentive in some cases is equal to 100% of the incremental cost of the more efficient technology. The MAP also assumes highly aggressive and costly advertising and marketing efforts."

As a follow-up to HREA-HECO-IR-2, HECO has established DSM program goals based on their MAP analysis referenced above. Will HECO now revise and update their MAP analysis to reflect promising new technologies, such as SAC, SWAC and customer-sited, electricity-generating renewables?

As an example, the analysis below indicates the potential for SWAC[4]:

> "On average, a ton of SWAC reduces energy demand by 3,475 kWh/yr and generation demand by 0.627 kW. Using HECO's current formula, the rebate to be provided to SWAC would be $252 (= 3,475 kWh x $0.05/kWh + 0.627 kW x $125/kW). The average cost of SWAC is $4,800/ton. A typical conventional air conditioning system with cooling towers costs $1,050/ton. Therefore, HECO's potential rebate is less than 7% of the differential cost of $3,750/ton. How can HECO justify such a low percentage for SWAC when they claim that "[i]n order to achieve the MAP the customer incentive in some cases is equal to 100% of the incremental cost of the more efficient technology?"

> "One ton of SWAC provides energy savings and demand reduction benefits that are equivalent to a solar water heating system. Solar water heating has been the centerpiece of HECO's residential DSM programs and has demonstrated its value to the utility system (and to the environment and local economy). The average solar water heating system costs about $4,700. A standard electric water heater might cost $500, for a cost differential of $4,200. HECO provides a rebate of $750 for a solar water heating system, or nearly 18% of the cost differential. HECO has proposed increasing the rebate to $1,000 (which we strongly support). This is nearly 27% of the differential cost. In addition, solar water heating systems are eligible for a 35% state tax credit and a 30% federal tax credit. Total incentives for a solar water heating system may approach $2,877, or nearly 69%, of the differential cost. Since each ton of SWAC provides benefits equivalent to one solar water heating system, how can HECO justify a rebate for SWAC that is only 1/3 to 1/4 that provided to solar water heating?"

[4] *Ibid.*

On the other hand, solar water heating systems are currently one of the few major energy conservation measures of which residential customers can take advantage. Water heating in Hawaii is the end use that uses the most electricity in homes that do not have air-conditioning. In contrast, commercial and industrial customers have many alternative cost-effective technologies available to them to effect energy efficiency. Thus, for customer equity and cross-county consistency reasons, and because the federal residential solar water heating tax credit expires at the end of 2007 (unless extended by Congress) HECO has proposed to increase the residential solar water heating rebate to $1000 from $750, as stated on pages 44 and 45 of HECO's FSOP.

HREA/HECO-IR-7 On page 16, HECO states the following:

> "HECO, HELCO and MECO ("Companies") have been very successful in their energy efficiency efforts under the existing market structure. From 1996 through 2005, the Companies' energy efficiency programs have reduced customers' consumption of energy by 2.4 million mwh and reduced peak demand by 66 megawatts ..."

Referencing the following additional comments and analysis from HSWAC[1] on the potential for SWAC:

> "There are an estimated 100,000 tons of developable SWAC potential on Oahu. Honolulu Seawater Air Conditioning intends to develop this potential over the next ten years (i.e., by 2016). These SWAC developments are projected to reduce energy consumption by 2.3 million MWh and peak demand by 63 MW over the 10-year period of 2009 – 2018. This represents a near doubling of all of HECO's DSM program benefits over a 10-year period (1996 – 2005). Benefits are even greater if one considers chilled water rerun condenser cooling effects.
>
> In spite of this, HECO has not included SWAC technology or SWAC projects under development and planned, in their most recent IRP plan. Even if HECO is able to achieve energy savings and demand reduction equal to the first 10 years of their DSM programs, this means that they have ignored a nearly equal potential contribution from SWAC."

HREA notes that HSWAC has discussed its technology with HECO and we are confused as to why HSWAC has not been included in HECO's 5-year Action Plan. Specifically, HREA does not believe HECO claim that "HECO, HELCO and MECO ("Companies") have been very successful in their energy efficiency efforts under the existing market structure" when promising technologies such as SWAC, and also SAC and electricity-generating, customer-sited renewables are not included in its 5-year plan. If HECO does not believe these technologies are ready for deployment at this time, would HECO consider partnering with industry on demonstration projects? If so, how could that be done within IRP?

HECO Response:

As stated in Section 13.2.2 of HECO's IRP-3 report, HECO believes that Sea Water Air Conditioning (SWAC) is a renewable energy technology that is emerging as a possible energy option for reducing the electricity requirement for air conditioning for commercial customers. Like other emerging technologies it is difficult to assess the timing of the commercial viability of the technology in a specific location. While HECO welcomes the development and installation of SWAC systems in Hawaii, at the time the DSM measure screening analysis was being conducted in the IRP-3 planning process there was substantial uncertainty as to when it would be installed and the date commercial operations would commence. Thus, the inclusion of SWAC in HECO's DSM Action Plan is not an issue of whether or not SWAC is technically feasible, but if and when it would be installed in Honolulu. Information regarding land acquisition or development agreements for the plant site, rights of way for chilled water distribution lines, and service agreements with facility and building managers would help HECO understand the progress SWAC is making toward commercial operations. HECO is willing to discuss a demonstration project with SWAC and, when such a project is established, the results could be incorporated into future IRP analyses.

However, regardless of the commercially viability of SWAC, HECO's existing DSM CICR program has the flexibility to provide incentives for customers to install systems using the SWAC technology. Further, as stated in its response to HREA/HECO-IR-3 and 5, HECO's market potential analysis did include the potential for energy savings in the facilities that would be targeted by the SWAC district cooling system.

In addition, as stated in its response to HREA/HECO-IR-2, HECO has not included customer-sited, electricity-generating renewables in its DSM Action Plan because those technologies are not demand-side measures.

example where a potential project could offer significant energy and demand savings, but could also meet the classic definition of a free-rider. Consideration must certainly be given to managing the level of free-riders and the related incentives paid to them.

HREA/HECO-IR-9 On page 40, HECO states the following:

> "Move the customer incentive funds among energy efficiency programs and among load management programs to address new technologies and to adjust to changes in energy codes and other external events that might impact HECO's ability to meet the energy and demand goals of the programs."
>
> "Increase or decrease individual measure incentive levels to respond to changes in participation levels and markets."
>
> "Add new measures, and establish corresponding incentive levels to address market opportunities."

Referring to previous IRs, HREA observes this is clear evidence of HECO's intent to encourage new technologies, but lack of follow-through on technologies such as SAC, SWAC and electricity-generating, customer-sited renewables. Again, can HREA get HECO's support to include these technologies its IRP plans and DSM programs?

HECO Response:

HECO disagrees with the statement regarding "lack of follow-through" on new technologies. New energy efficiency technologies, such as SWAC and SAC, are provided incentives through the C&I Customized Rebate Program if those technologies can be shown to be cost-effective. However, as indicated earlier in its response to HREA/HECO-IR-2, electricity-generating, customer-sited renewable technologies are outside the scope of HECO's DSM programs, as defined by the IRP Framework.

HECO maintains that renewable technologies are adequately and appropriately addressed in its IRP process, specifically, the identification and integration of supply-side resources.

HREA/HECO-IR-11 On pages 82, HECO states the following:

> "HECO and many other stakeholders participated in the IRP-3 effort. (See HECO's IRP-3 Report, Chapters 3 and 12.) This effort analyzed many options for meeting the electric demand of HECO's customers throughout the planning time horizon. HECO's proposed DSM programs were the subject of an intensive analysis that reviewed the best technology applications from programs across the nation as well as applications unique to Hawaii. These DSM program proposals are a key component of HECO's and Oahu's energy future."

HREA takes issue with the claims made above. Per our previous IRs, HECO appears to take a much different view of which DSM technologies should be included in HECO's DSM program and under what conditions. How can we resolve this apparent impasse, especially at this time when HECO claims there are impending capacity shortfalls on Oahu?

HECO Response:

As stated in HECO's responses to HREA/HECO-IR- 2, 5 and 7, HECO agrees with HREA that sea water air-conditioning, if shown to be cost effective, should be eligible for DSM program incentives under HECO's C&I Customized Rebate Program. In fact, much of the potential energy savings that would be captured by a seawater air-conditioning district cooling system have been included in HECO's market potential studies (see HECO's response to HREA/HECO-IR-3).

HECO agrees that all possible solutions to the current reserve capacity shortfall situation must be evaluated, and if the benefits outweigh the cost and resources are available, also implemented. However, not every solution can be effected through HECO's DSM program. The IRP Framework, developed in a collaborative manner by a number of parties and approved by the Commission defined the scope of demand-side management programs as "programs designed to influence utility customer uses of energy to produce desired changes in demand". However, DSM comprises just one component of the portfolio of resources that HECO is pursuing to resolve the reserve capacity shortfall. As stated in HECO's 2006 Adequacy of

Supply filing, dated March 6, 2006, HECO's Action Plan and Mitigation Measures also include improving the availability of HECO's generating units, maintaining or improving the availability of independent power producers, accelerating the installation of the next generating unit, installing Distributed Generation, and implementing a public notification program (page 37, and Appendix 4).

the Commission has approved after considering program cost-effectiveness. Thus, the cost-effectiveness criteria would have already been applied by the Commission. Therefore, HECO does not envision that there would need to be a cost efficiency element to each goal.

LOL/HECO-IR-2

If cost were not a consideration, what level of average and peak electric load reductions could be achieved for each island, that is, what penetration levels are possible?

HECO Response:

If cost (i.e., near term rate impacts) were not a consideration then the amount of average and peak electric load reductions that could be achieved for each island would theoretically approach the Maximum Achievable Potential (MAP) as identified in HECO-1101, Docket No. 04-0113, HECO's 2005 TY rate case. However, the ability to achieve the MAP is constrained by the degree to which the DSM programs are accepted by the market. Added program expenses to overcome market barriers and increase market acceptance by raising customer incentives and extending outreach programs will help, but may not result in attaining this maximum upper boundary for energy efficiency and load reduction savings.

LOL/HECO-IR-3

a. Is HECO a member of the Hawaii Solar Energy Association?

b. Is HECO a member of any other party or participant?

HECO Response:

a. Yes, HECO has been a member of the Hawaii Solar Energy Association since 1998. Ron Richmond, a HECO Customer Energy Program Analyst is an elected director and secretary of HSEA but has recused himself from participation in the development of any of HSEA's Energy Efficiency Docket positions.

b. No.

KIUC-SOP-IR-2 **Ref: HECO Companies's Joint Final SOP, Page 7.**

The HECO Companies' Joint Final SOP states, in relevant part:

> On April 4, 2006, April 26, 2006 and May 11, 2006, the parties/participants held settlement discussion meetings to attempt to reach agreement/partial agreement on the issues for Commission review and approval, which would limit the issues needed to be addressed in the parties/participants FSOPs.

In connection with the above, the following summarizes KIUC's understanding of the consensus reached by the parties/participants present at the May 11, 2006 settlement meeting on four of the five issues established for this proceeding as they pertain to KIUC, together with some background on each issue:
Docket Issue No. 2: What market structure(s) is the most appropriate for providing these or other DSM programs (e.g., utility-only, utility in competition with non-utility providers, non-utility providers)?

Consensus: As it pertains to KIUC, an electric cooperative essentially owned by its customers, there should be no change to the market structure by which KIUC currently develops and administers its DSM programs, provided that, as recommended by HREA and agreed upon by KIUC, KIUC hire a DSM consultant and/or consult with a third party or fund administrator if and when appropriate.

Background:

- Under the current structure, KIUC, at its discretion, either conducts its own DSM/energy services programs or contracts it out to a third party as appropriate. During the meeting, KIUC stated that this structure best supports the cooperative model, whereby DSM could be integrated with other energy services offerings.
- KIUC also noted that it strives to provide a level of service to its members even higher than that allowed or established by the current DSM evaluation criteria, and as such, KIUC is currently implementing programs that go beyond simple cost effectiveness. Examples given were: (1) KIUC's current appliance rebate program, whereby KIUC pays a rebate to any member that purchases a qualifying energy efficient appliance, and (2) KIUC's current solar rebate and loan program whereby KIUC either pays rebates or provides (through third-party lending institutions) no-interest loans for the installation of solar water heating systems. In both examples, KIUC does not screen for cost effectiveness and the programs are funded by the program budget approved by KIUC's Board of Directors (who are elected directly by KIUC's customer/members to represent their interests).
- KIUC also noted that the direct install DSM programs offered by KIUC during the past 7 years have significantly penetrated the residential markets. As a result, the current remaining markets may be too small to overcome the

Docket Issue No. 5: Whether DSM incentive mechanisms are appropriate to encourage the implementation of DSM programs, and, if so, what is the appropriate mechanism(s) for such DSM incentives?

Consensus: As it pertains to KIUC, the use of financial incentives to facilitate the pursuit of DSM programs are not applicable to KIUC. KIUC's ratepayers and shareholders are essentially one and the same, and as such, any financial incentive charged to the ratepayers to benefit the shareholders is essentially a charge that will be returned to the ratepayers (aka shareholders).

In addition, with respect to Docket Issue No. 1 (Whether energy efficiency goals should be established and if so, what the goals should be for the State), it is also KIUC's understanding that, during prior discussions amongst the parties, an agreement was also reached that energy efficiency goals should not be established, as it pertains specifically to KIUC.

Please confirm whether KIUC's understanding of the above consensus is correct, as they apply to KIUC. If not, please explain why KIUC's understanding is incorrect.

HECO Response:

HECO recognizes that KIUC, as a cooperative, has legitimate reasons that support its position to be considered separately from investor-owned, for-profit, utilities for the purposes of DSM market structure, cost recovery, and utility incentives. Thus, HECO fully expects that the Commission will take these considerations into account in its decision.

The Company does not agree with KIUC that the "cost recovery issue seems to involve whether DSM program costs should be recovered from the utility's ratepayers or instead paid by the utility's shareholders" as it states above in Docket Issue No. 4. It is HECO's understanding that none of the parties in this proceeding have recommended that utility shareholders pay any portion of DSM program costs. Instead it appears that the consensus among the parties is that all legitimate program costs can be fully recovered from ratepayers.